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Cover Image: A view of the LPU unit at Qatar-Shell's Pearl GTL Plant in Doha, Qatar. Photo courtesy of Shell Photographic Services, Shell International Ltd.

HP Industry Perspectives

1Q project announcements this year down vs. 1Q 2021

New capital project announcements are down 27% in 1Q 2022 vs. 1Q 2021. Gulf Energy Information's Global Energy Infrastructure database counted 48 new project announcements in 1Q 2021. This year, 1Q capital project announcements globally have dropped to 35.

Where are these projects? Most new capital projects this year are in the Asia-Pacific region, which accounted for 46% market share in new project announcements. This is an increase of 11% vs. 1Q 2021. Most new project announcements in Asia are petrochemical capacity additions in China and India. These two nations are investing heavily in new petrochemical capacity to satisfy future demand. The Asia-Pacific also accounts for the largest market share in total active projects (FIG. 1).

At 23%, the Middle East represented the second-highest market share in new project announcements in 1Q. Like Asia, most new projects announced this year in the Middle East are for new petrochemical capacity builds. The region is investing in incorporating new petrochemical processing units in existing refining operations, as well as building grassroots chemical units.

A breakdown of new project market share is detailed here:

- Africa—3%
- Asia-Pacific—46%
- Western Europe—3%
- Eastern Europe, Russia and the CIS—17%
- Latin America—2%
- Middle East—23%
- U.S.—6%.

The largest shift in new project market share has been within the petrochemicals sector. In 1Q 2021, the petrochemicals sector comprised 21% of new project announcements. This year, the sector's 1Q market share has increased to nearly 65%. HP

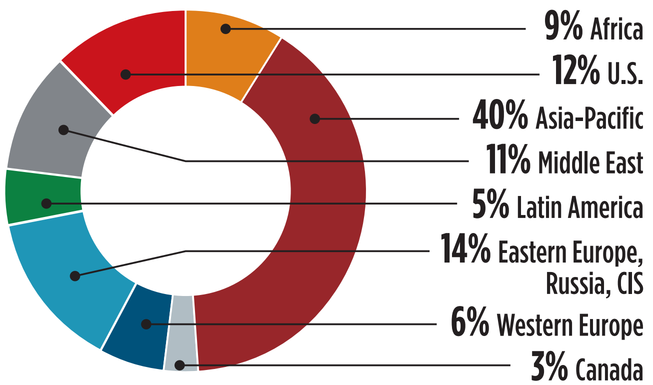

FIG. 1. Total active project market share by region.

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Advancing maintenance ultimately leads to increased reliability

This year, *Hydrocarbon Processing* is celebrating its 100th anniversary. Throughout this year, the editors are publishing excerpts from past issues. These articles (*HP* Flashback) are in the History of the HPI section. *HP* Flashback is a mixture of technical articles, headlines and columns published throughout various decades. For example, this month's *HP* Flashback features material that was published in the 1950s of *Petroleum Refiner,* the forerunner to *Hydrocarbon Processing.*

Throughout our 100-yr history, the topics of maintenance and reliability have always been prevalent. Refineries and petrochemical plants are a collection of highly-technical process units that undergo the harshest environments on the planet. These units operate under intense pressures and temperatures and must be maintained to ensure proper operation. Failure to do so could result in off-specification production, decreased efficiency, increased energy needs and emissions, unit shutdown or, in a worst case scenario, a safety incident or possible explosion.

Process unit maintenance and reliability are crucial to ensure safe and efficient operations; a robust maintenance strategy promotes optimal performance. Maintenance should not be considered an expense, but rather a value-added operation to ensure unit reliability and uptime.

Maintenance spending. In *Hydrocarbon Processing's HPI Market Data 2022* report, the editors forecast global maintenance spending to reach nearly $70 B. As refineries and petrochemical plants age, maintenance plans and strategies become even more important. These programs help maintain unit effectiveness and provide a safer and more reliable working environment.

Special focus. New tools, technologies and services are continuing to advance maintenance programs around the world. For example, new digital technologies can provide plant operators with more data and insight into the health of equipment, greatly enhancing operations by providing a detailed look at how equipment is operating and when it will need to be serviced and/or replaced.

These new digital tools are even making incredible strides in training refining and petrochemical plant personnel on many aspects of maintenance, operations and safety. Digital technology adoption can provide plant personnel with multiple benefits at their fingertips, changing the way the hydrocarbon processing industry operates and making operations safer for plant personnel.

Because of the seriousness of maintenance and reliability programs, *Hydrocarbon Processing* continues to provide an in-depth look at this topic throughout its editorial lineup. This month's Special Focus section features several technical articles on how operators, vendors/suppliers, consultants and technical teams are advancing the practice of maintenance to boost the reliability of process units and equipment. These articles include the following topics:

- Investigating and diagnosing foaming issues during the startup of a tail gas treating unit
- Using reverse engineering to repair obsolete equipment that has no existing original equipment manufacturer or spare parts
- Rerating processing equipment to adhere to new plant conditions to ensure proper operation
- Troubleshooting and using failure analysis to find the root cause of failures to remedy the situation or avoid future occurrences.

Refinery and plant maintenance is inevitable. Advancing the way the industry conducts maintenance will ultimately lead to improved reliability. HP

INSIDE THIS ISSUE

J. KRIMMEL, Pinnacle, Houston, Texas

The economics of reliability: Global chemicals

Chemical manufacturers worldwide are navigating an inflection point. Following the pandemic-fueled demand crash of 2020, a strong but stilted recovery unfolded in 2021. In the latest *World Economic Outlook* (January), the International Monetary Fund (IMF) announced global economic growth increased by 5.9% in 2021 and is forecast to increase by 4.4% this year. The chemicals industry is feeling this surge. After recent revenue and profit declines, many chemical companies are unprepared to fully capture today's market opportunities.

In the author's company's report, the performance of global chemical companies as it relates to industrial reliability was analyzed. The report defines reliability as a measure of how often something performs when you want it to. In the context of the industrial chemicals segment, the performance of the machinery and equipment assets responsible for processing feedstock into finished goods is of prime interest. These assets could be pressure vessels, storage tanks, pumps, compressors, heat exchangers, piping, mixers and countless other equipment types.

Specifically, interest lies in estimating how much global chemical companies spend on reliability initiatives, and what kind of results these companies see in return. Reliability initiatives include inspections, repairs, planned and unplanned maintenance, upgrades, expansions, overhauls and replacements, along with all the necessary materials, supplies and labor.

Three major reliability trends have affected or will affect the global chemicals sector. These include:

1. The chemicals sector experienced a decline in revenue and profits in 2019 and 2020. In 2019, oil prices fell by 10%, dragging down pricing for many chemicals. In 2020, the COVID-19 pandemic destroyed demand globally, causing chemical companies to reduce their output.
2. In response to falling revenue and profits, chemical companies reduced their capital expenditures. Many of these companies saw their machinery and equipment asset bases stagnate or shrink. Even when accounting for the slightly smaller asset base, the world's largest chemical companies generated fewer dollar-for-dollar profits in 2019 and 2020 than they did in 2016, 2017 and 2018.
3. The market picture changed dramatically in 2021 and is now abound with growth opportunities. However, after years of reduced capital expenditures and diminished asset productivity, chemical companies are struggling to fully take advantage of market tailwinds.

Reliability is a common thread that runs through all three of these elements. Reduced investment spending stresses the reliability of existing assets. Suboptimal reliability impairs asset productivity, which weighs against profits. In a market environment where response times are critical, improved equipment reliability can be a timely and cost-effective way to capture opportunities while pursuing longer-term, new construction in parallel.

Analysis methodology. The chemical reliability report relied on the following three data sets:

1. The World Bank publishes data around the value added by the chemicals industry on a country-by-country basis. The report uses this data to estimate the total reliability spend of this segment of the economy.
2. The report also studied the annual financial and operational reports of 18 of the largest chemical companies in the world. These reports provide much more detail than what can be found through the World Bank and provide more about the evolving competitive landscape in the chemicals space.
3. The U.S. Bureau of Labor Statistics publishes a producer price index for domestic chemical manufacturers. This data set provides a sense of how chemicals prices have changed over time, from which important supply vs. demand details can be inferred.

The industrial chemicals sector has witnessed two consecutive years of declining revenues and profits. The author's company estimates that global chemical companies spend approximately $236 B/yr on reliability. FIG. 1 shows the revenue, operating income and operating margin for 18 of the largest chemical companies from 2016–2020. There is a steady

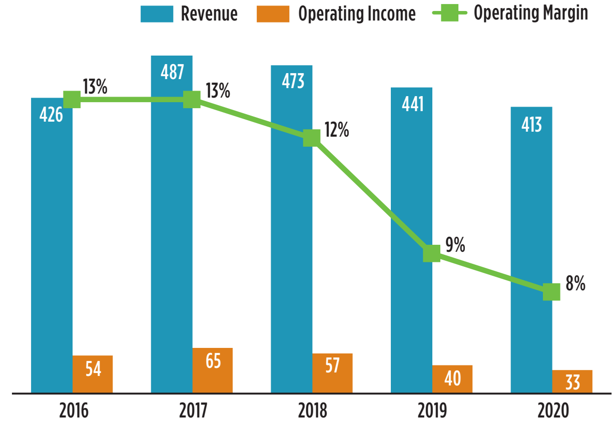

FIG. 1. Revenue, operating income and operating margin for 18 of the largest chemical companies, 2016–2020.

decline in revenue from $487 B in 2017 to $413 B in 2020. Over this same period, operating income and operating margin have both fallen continuously.

The dynamic nature of the chemicals market has brought a heightened focus on the need to optimize reliability and asset performance.

FIG. 1 shows the evolution of important metrics from the income statements of the companies tracked. Having a deep interest in industrial reliability, the author's company wanted to study asset productivity. If asset bases are shrinking proportionally to declining revenues and profits, operators may be slightly scaling down existing operations. However, if revenues and profits are falling more quickly than asset bases are shrinking, then we are most likely seeing deterioration in asset productivity.

Value of machinery and equipment assets has fallen in the chemicals industry. Continuing with the analysis, the author's company studied the balance sheets of the 18 largest chemical companies, specifically looking at the value of their machinery and equipment (M&E) assets, which is a subset of the property, plant and equipment (PP&E) line item. The analysis focused on machinery and equipment since these are the productive assets most directly involved in the processing of chemicals. The property subset is important, but interest in industrial reliability steers the focus toward machinery and equipment specifically. **FIG. 2** shows the size of the productive asset base for the companies studied from 2016–2020. Their productive asset base has shrunk from its peak, and the most productive assets—the machinery and equipment—make up a smaller share of the remaining asset base than they did previously.

The economic value of the asset base of this portfolio of companies contracted by 4% points from 2018–2020. One important mechanism that can drive this contraction is a conservative capital expenditure program. If these companies invest below the level of existing depreciation, the value of the asset base will shrink. Another mechanism that could drive this outcome would be asset impairments, where value is marked down if any of these assets support production that is no longer economical.

We have seen from **FIG. 1** that revenue and operating income has been trending down in recent years for some of the world's largest chemical companies. **FIG. 2** showed that while the productive asset base for these companies has shrunk, operating income has declined more rapidly. For every piece of machinery and equipment these companies own, they are generating fewer profit dollars today than they did in the past 2 yr–4 yr. The urgency to improve asset uptime and performance is very real in this sector of the global economy.

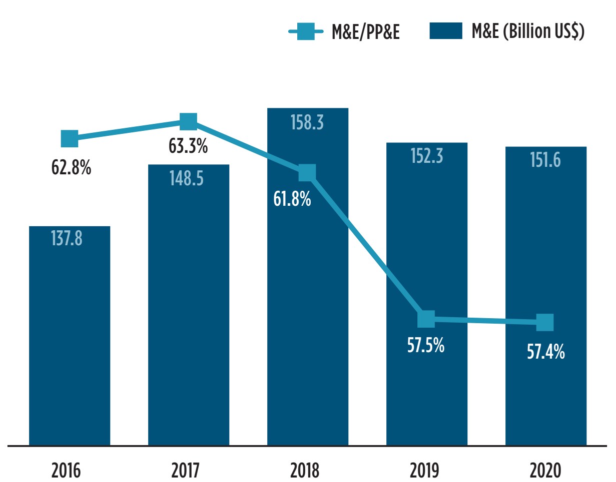

FIG. 2. Productive asset base (M&E and PP&E) for the companies studied from 2016–2020.

Reliability spending varies dramatically between chemical manufacturers. A comparison of reliability spending intensity across 18 chemical industry giants is shown in **FIG. 3.** The most important observation from **FIG. 3** is the wide range of reliability spending intensities across the industry's largest players. From 2018–2020, two companies devoted less than 1% of revenue to reliability spending. One company spent more than 2.5% of revenue on reliability, while one company spent more than 3% of revenue in this area.

FIG. 3 also shows a wide range of revenues, even though all these companies have multibillion-dollar revenue streams. Interestingly, the wide range of spending intensity exists even with companies in the same revenue range. Eight companies have average annual revenues between $10 B and $20 B. Of these eight companies, the smallest reliability spending intensity is at 0.8% of revenue, while the largest reliability spending intensity is more than three times larger at 2.7% of revenue. The point is that there is a wide range of reliability spending, even when the range of revenues are constrained.

Within this portfolio of large chemical manufacturers, there was no correlation between the size of the revenue stream and the intensity of reliability spending. The largest company in the portfolio generates about ten times the revenue of the smallest company, but the largest company directs slightly less of its revenue toward reliability spending than the smallest company. Spending intensity is most often uncorrelated with the size of the operator.

FIG. 3 provides circumstantial evidence that the average reliability program has not been optimized. If these 18 companies were collectively spending near optimal levels on reliability, there would likely be an economy of scale effect. The largest companies would spend less than their smaller peers, as the fixed cost of an optimized reliability infrastructure is spread over many operating facilities. Instead, reliability is too often practiced in a parochial sense, where each facility defines its own reliability protocols. In these cases, performance is sensitive to the personal philosophies and experiences of onsite reliability leaders, which is reflected in a wide range of spending intensities for companies of all sizes.

Insights. Industrial reliability has always been a critical performance driver for chemical manufacturers. Today, against a

turbulent macroeconomic backdrop, the returns to optimized reliability programs are greater than ever. In this report, the author's company analyzed several data sets to better understand the challenges chemical producers face regarding reliability. The following four key conclusions can be made from the investigation:

1. **Global chemical companies spend nearly $250 B/yr on reliability, with the Asia-Pacific region and North America accounting for two-thirds of the total.** Specifically, it is estimated that these companies spend around $236 B/yr on reliability initiatives, which include inspections, repairs, maintenance, upgrades, expansions, overhauls and replacements, along with all the necessary materials, supplies and labor.
2. **The financial performance of many large chemical companies deteriorated in 2019 and 2020, as revenues and profits both fell from their 2018 highs.** The annual reports of 18 large global chemicals companies were studied to better understand their reliability performance. The first step of the analysis was to study these companies' income statements. For many of these companies, revenue, operating profit and operating margin all fell in 2019 and again in 2020. These declines are not all the result of the COVID-19 pandemic. Oil prices fell by 10% year-over-year (y-o-y) in 2019, which pushed down the prices of industrial chemicals broadly. The pandemic accelerated the slide downward. The result was two consecutive years of challenged financial results.
3. **In response to deteriorating financial performance, chemical companies cut back on capital expenditures, which impaired asset productivity.** It was noted that many large chemical companies experienced falling revenues and profitability in 2019 and 2020. One important consequence was that these companies had less capital available to reinvest in the business. As a result, capital expenditures fell, which led to the stagnation, and even slight shrinkage, of the productive asset base. Interestingly, even when the analysis was normalized for the smaller asset base, these companies still generated fewer profit dollars in 2019 and 2020 than they did in 2018. Deferring capital expenditures was an understandable response to shrinking revenues and profits, but existing assets were undoubtedly strained. These bills are now coming due, with reliability spending likely to increase in the next several years to make up for the gap of the past 2 yr.
4. **As the macroeconomy continues to recover, chemical companies are scrambling to capture the plethora of newly available market opportunities.** According to the IMF, the global economy contracted by 3.2% in 2020. In 2021, the market winds changed. Global economic growth increased by 5.9% and is forecast to increase by 4.4% this year. Chemical suppliers are already feeling this uplift. In the U.S., the U.S. Bureau of Labor Statistics has shown that industrial chemicals pricing was up 30% y-o-y in 2021. Several of the world's largest chemicals companies have publicly declared their intention of expanding existing plant capacity to meet rapidly growing customer demand. The quick swing from pandemic-fueled demand destruction to recovery and growth in many commodity markets has left chemical manufacturers scrambling to add capacity for high-value products.

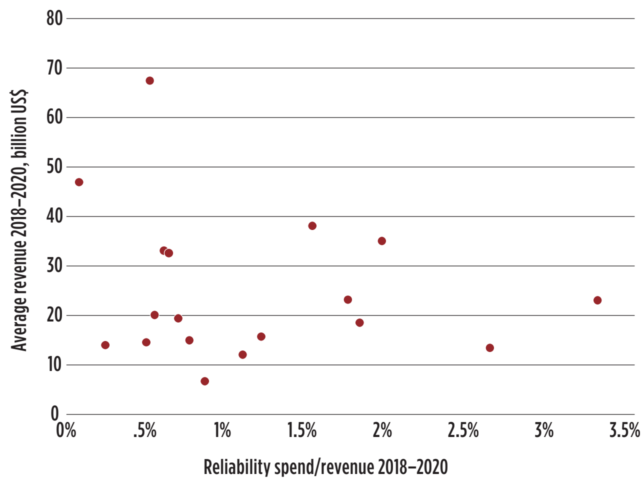

FIG. 3. Reliability spending intensity across 18 of the largest chemical companies, 2018–2020.

Reliability is the common thread. Reliability is the common thread that runs through this story. Eliminating wasted spending is the first order of business. A wide range of spending patterns exist, with large chemical companies dedicating anywhere from < 1% to > 3% of revenue to reliability expenditures. The wide range in spending intensity suggests an opportunity around cost avoidance. Some inspection, maintenance and overhaul activities simply do not generate a positive return. Cutting these expenditures provides quick relief to profitability.

However, the largest gains can be found when reliability programs are modernized as part of the industry's ongoing digital transformation. Today's reliability data strategies are too often shortsighted, subjective and siloed. Too much data is collected in some places, while too little is collected in others. More comprehensive, data-driven reliability programs can help expose the causes of many unexpected failures and identify ways to mitigate the resulting unplanned downtime. These programs can be fully implemented in much less time than it takes to startup new construction. While the capacity gains from new construction are undeniably large, incremental capacity gains in existing plants can be captured more quickly, and typically ride on a fixed-cost base the company already bears. In these cases, profitably grows aggressively. HP

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Valuable trends combine innovation and time management

These days, regrettably, it is not unusual to encounter shallow thinkers. A few months ago, we received a request from a reliability professional overseas. He asked the author to clarify a discrepancy between one of his texts, which recommended an oil ring immersion depth of 5/16th of an inch (in.), and another one of his texts that recommended an oil ring submergence of 8 mm. For the record, 5/16 in. × 25.4 mm/in. = 7.9 mm. Better yet—and assuming that you are a manager—consider asking staffers to become familiar with lubrication methods that avoid failure-prone components.

I can only assume from the serious tone of his email that the questioner was not trying to be funny; his request supports my observation that common sense is in short supply today. I am also serious when I tell you that if this 8 mm vs. 7.9 mm individual reported to me, I would ask him to read up on what oil rings do in a pump bearing housing and whether he is using his (and his company's) time wisely.

So, it is an unhealthy trend if people are not inquisitive and are offering unsupported opinions rather than facts. It is also an unhealthy backward trend when people are impressed by the sheer size of a supplier company, or the low bid price for certain products.

Fortunately, we see a good trend in the approach taken by "best-in-class" user companies. Chances are that looking at the top 5%–10% (in profitability) of fluid machinery users and collectively calling them best-in-class, we will see a steep upward trend in their use of innovators. Remember, again, that innovators create demand among the true reliability professionals. Innovators do not wait for the average user company to request this, that or the other thing. They make their innovations known to reliability professionals and align their thinking with each other. Putting it another way: they move forward together, and they prosper together.

So, what does a true reliability professional do? We could provide a detailed role statement with a list of 20–25 items. Such role statements would clearly establish that conscientious professionals will be proactive—rather than reactive—in their contributions. He or she will have decided, before signing on virtually or reaching their employer's parking lot on ordinary workdays, what it is they will be working on. I could tell you that as these true professionals drive home at the end of the workday, they will ask themselves whether they have, in fact, accomplished what they *wanted* to accomplish on that day. The quality of their work product will be the principal gauge by which they conduct this self-assessment. Just imagine how rewarding it will be for them to say, "Today, I have added some real value."

Innovation can improve existing machinery. The author recalls three of his (and perhaps the reader's) professional colleagues who lived in the Houston, Texas area. Throughout their lives, Charlie Jackson, Ed Nelson and (until 2019) Paul Barringer preached equipment reliability. These experts taught that every maintenance event should be viewed as an opportunity to upgrade your equipment. In other words, every maintenance event deserves our attention, and we must determine if an upgrade is cost-justified. Jackson, Nelson and Barringer knew that the difference between a maintenance engineer and a reliability engineer is easy to define: maintenance engineers put their effort into maintaining a machine in the as-designed condition. They get activated the moment the machine is available for maintenance or is taken down for repairs.

We may argue about definitions and (occasionally unpleasant) connotations, but maintenance—broadly speaking—is a reactive job, whereas reliability engineering implies working to eliminate the need for most maintenance activities.

In sharp contrast, the reliability professional's workday is almost entirely proactive, using any available time to provide the answers to three questions:

1. Is an upgrade possible?
2. If yes, is an upgrade cost-effective?
3. Which innovative technology provider should our company select to implement the combined repair and upgrade tasks?

Needless to say, reliability professionals work with innovators and make them their technology resource. The innovator assists the reliability professional in working up and explaining payback calculations. Together, the reliability professional and upgrade provider research and document prior experience. Both participate in defining the field experience at other client sites; this can be done without breaching confidentiality. They join in preparing a presentation to the reliability professional's management. This is part of a structured machinery quality assessment (MQA) process, which should be in the user-purchaser's budget, and which contributes to decades of future machinery reliability. HP

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Investigation and diagnosis of startup foaming issues at a new tail gas treater

In May 2021, Phillips 66 started up a new methyl diethanolamine (MDEA)-based tail gas unit at its Belle Chasse, Louisiana, refinery. Shortly after startup, foaming in the amine regenerator forced the unit to shut down. Amine manufacturers had declared *force majeure* after the February 2021 cold snap in Texas, so the refinery was forced to find alternative solutions to changing out the amine. This article will discuss interpretations of ion chromatography (IC), along with comprehensive two-dimensional gas chromatography-mass spectrometry results that pertain to the root cause of foaming. Also discussed will be acceptable regenerator steam and reflux accumulator purge rates, the appropriate antifoam injection locations, the use of carbon beds for contaminant removal, and the utilization of carbon beds to remove submicron iron sulfide particles, as well as tray ratings, equipment design details and sulfur recovery unit (SRU) operation.

Background. Prior to 2021, the Belle Chasse refinery operated with two parallel Claus SRUs that sent tail gas to a single MDEA-based tail gas unit. The refinery could divert SRU tail gas from either SRU to a single forced draft incinerator during startups, shutdowns and emergencies. The refinery needed a new tail gas treating unit (TGTU) to provide redundant TGT capacity for the refinery, thus allowing the refinery to continue to operate and comply with New Source Performance Standards (NSPS) Subpart J requirements while the existing TGTU was undergoing turnaround maintenance and was consequently out of service.

New TGTU design—Process flow diagram. The new TGTU was designed to handle Claus tail gas from two SRUs that have an operating capacity of roughly 50-long-tpd and 75-long-tpd sulfur, respectively. A new natural draft incinerator was provided to complement the existing incinerator.

Claus plant tail gas from either SRU can be sent to the new TGTU. The Claus plant tail gas is first heated by a 600-psig steam heater to attain adequate reaction temperatures for the cobalt molybdenum (CoMo) catalyst to convert sulfur species to hydrogen sulfide (H_2S) (**FIG. 1**). The hydrogen necessary for the reactions in the CoMo catalyst bed to proceed is supplied by reformer hydrogen. There is no waste heat boiler downstream of the CoMo catalyst bed. The new TGTU was originally designed with a spray cooler on the quench column inlet piping, but the spray cooler was never installed. The quench water heat exchangers, which use cooling water, provide all the cooling for the quench column. The quench column has a single bed of random packing. The circulating quench water has a filter designed for 25% of the normal quench water flow. Quench water pH is continuously monitored online upstream of the quench water coolers. If the quench water pH drops, caustic [sodium hydroxide (NaOH)] is added automatically to increase the pH of the quench water.

The MDEA section of the TGTU uses generic MDEA. Designed MDEA circulation is 130 gpm of 30 wt% MDEA solution. The 4 ft-diameter MDEA absorber is a column with two 12 ft-deep beds of random packing and an overhead demister (**FIG. 2**). Absorber overhead is sent directly to the incinerator. A carbon bed is provided on the rich amine leaving the absorber. Particulate filters are provided upstream of the carbon bed to prevent

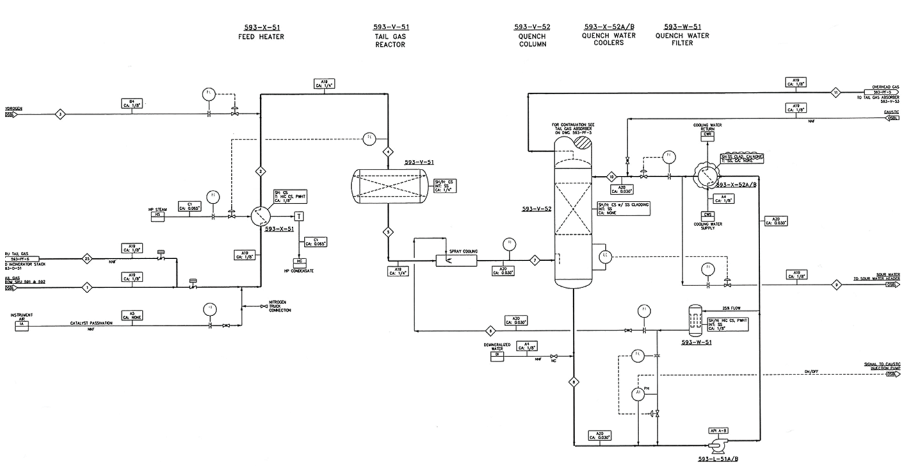

FIG. 1. CoMo reactor and quench column.

it from plugging, and provided downstream of the carbon bed to catch carbon particles. Rich amine passes through two lean/rich shell-and-tube heat exchangers before entering the trayed amine regenerator. The 3 ft-diameter amine regenerator has an overhead air-cooled heat exchanger designed to cool the overhead gases to 120°F (48.89°C). Reflux is sent back to the three-tray reflux section in the amine regenerator. Facilities are provided to purge a small portion of the reflux. A cooling-water heat exchanger cools the lean amine to a 100°F (37.78°C) design temperature before entering the absorber. The quench column, amine absorber and amine regenerator are stainless-steel clad.

Equipment preparation highlights. New towers and piping were washed with hot condensate to remove debris and chemical contaminants from the new equipment. The tail gas catalyst was pre-activated offsite with a vendor's proprietary process to avoid the use of acid gas for presulfiding, and so that the catalyst could be stored in situ without a nitrogen blanket.

Initial startup. The tail gas catalyst bed temperature was raised to a minimum of 420°F (215.56°C) before adding H_2S-containing gas to the TGTU. Plant nitrogen was used as the process gas to heat the catalyst. MDEA solution was circulated for 5 d before any H_2S-containing gases were routed to the new TGTU. Quench column circulation was also established before adding feed. The unit started up in the second week of May 2021.

Claus tail gas from the smaller Claus unit was initially added to the new TGTU. This Claus unit does not process ammonia acid gas from a sour water stripper and would be a stable source of Claus tail gas for the startup. The MDEA solution was water-white before Claus tail gas was added. Within hours of introducing Claus tail gas, however, the amine solution turned black. Engineering staff interpreted the source of the black color to be iron sulfide particles generated as the H_2S-containing amine began establishing a protective iron sulfide on carbon-steel piping and equipment. Engineering's initial course of action was to let the new 10-micron particulate filters remove particles in the amine. At this time, some differential pressure excursions were reported in the amine regenerator. The operations team maintained staffing at high levels to accommodate the frequent filter changes. Within 72 hr, the amine was water-white again, although frequent filter changes were required. Unfortunately, even though the amine solution color was good, foaming issues on the amine regenerator were frequent and severe enough that stack emissions were rising.

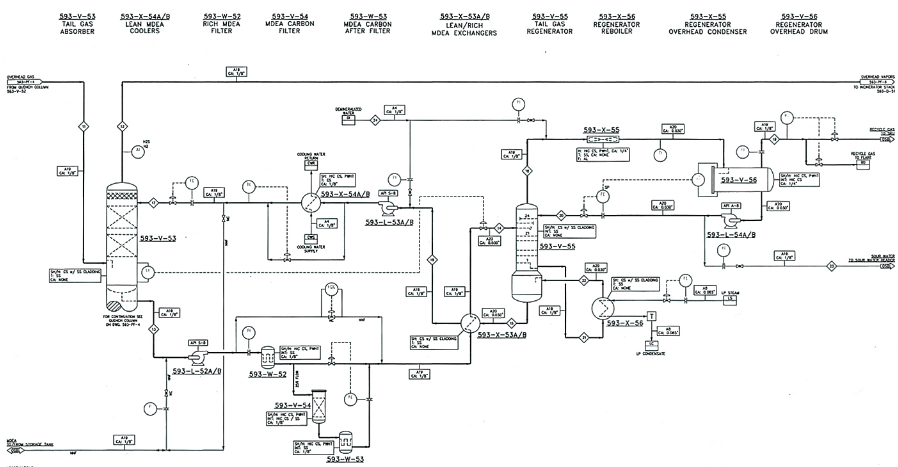

FIG. 2. MDEA section of the new TGTU.

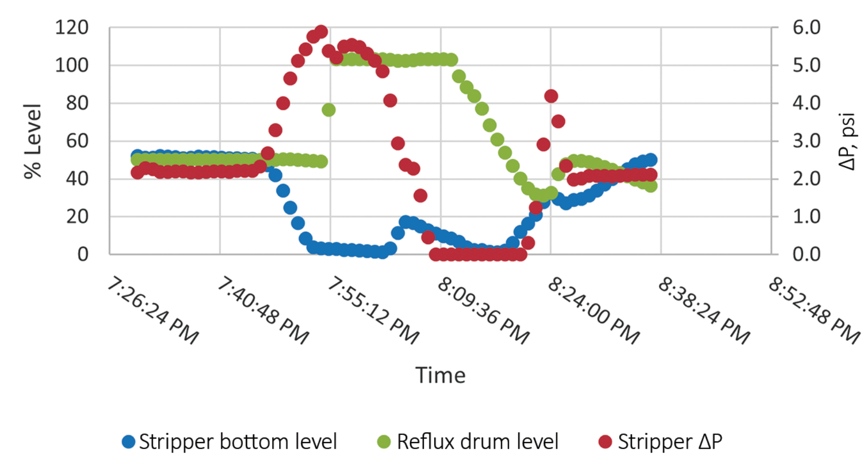

FIG. 3. TGTU regenerator performance.

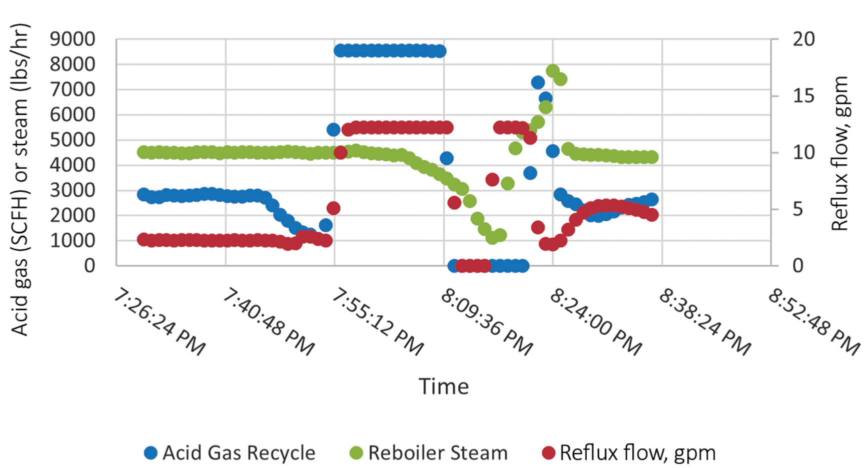

FIG. 4. TGTU regenerator performance.

Foaming diagnosis. The TGTU amine regenerator performance during 1 hr in June 2021 is illustrated in **FIGS. 3** and **4.** The stripper bottom level and reflux drum level shown in **FIG. 3** are stable until the stripper tray pressure drop starts rising quickly at approximately 7:45 p.m. Minutes later, the stripper bottom level drops quickly, followed by the reflux drum level quickly rising to 100%. **FIG. 4** shows that acid gas recycle initially drops when the stripper pressure drop starts rising, and then goes off scale high when all the liquid holdup in the column is pushed overhead into the reflux accumulator. The behavior shown in **FIGS. 3** and **4** is consistent with foam starting first in the stripping section of the regenerator, with amine unable to reach the bottom of the regenerator and then "burping" into the reflux accumulator. **FIG. 4** also indicates reflux flowback to the stripper going off scale high as the operations team attempted to reduce the reflux accumulator level. **FIG. 4** shows that steam had to be cut to lower the stripper pressure drop and to avoid a reflux accumulator overfill. **FIGS. 3** and **4** indicate classic foaming behavior, with foaming far worse in the trayed amine regenerator than in the packed amine absorber. The TGTU MDEA absorber's ΔP and level control were not affected as significantly during the same time interval. The TGTU absorber bottoms level was maintained in the 45%–52% range, and the TGTU absorber ΔP stayed within a tight range of 0.35 psi–0.71 psi. Similar behavior repeated itself during similar time periods for the next few weeks.

SRU troubleshooting. The larger 75-long-tpd SRU had plugging concerns during the startup of the new TGTU. Sulfur carryover from the final condenser into the TGTU catalyst bed was also hypothesized. It was initially thought that these issues might be related to TGTU foaming, and troubleshooting efforts began to resolve these issues.

The largest pressure drop in the SRU was measured across the first converter catalyst bed. Heat transfer in the first converter bed reheater was also severely limited, resulting in poor SRU conversion during the new TGTU startup. During this time, a low outlet temperature from the first sulfur condenser was evident. The plugging could be temporarily alleviated by unplugging the seal leg, leaving the first condenser. When the first seal leg started flowing liquid sulfur, the performance of the first reheater gradually improved as sulfur melted away from the first reheater. As the reheater performance improved, the temperature of the first catalyst bed started rising, improving overall sulfur plant conversion.

At this time, the refinery hypothesized that there was a water leak in the first condenser that was plugging the sulfur rundown leg and allowing sulfur to accumulate and then get entrained and carried into the first reheater where the sulfur stuck onto cold parts of the reheater. There were also some thoughts that the carryover was due to poor heat transfer from the steam tracing on the aboveground sulfur seal legs. To prove conclusively that there was a water leak from the condenser and not from the upstream waste heat boiler, the refinery decided to conduct radioactive tracer testing on the upstream waste heat boiler and the first condenser.

Radioactive tracer was injected into the boiler feed water that supplied the waste heat boiler and first condenser. Tracer was injected on separate days into the boiler and condenser. Tracer levels were measured in the TGTU's quench water on each day. Radioactive tracer tests showed conclusively that the first condenser was leaking—and that there was no leak in the waste heat boiler. Maintenance efforts could be concentrated on fixing the first condenser.

Sulfur carryover from the final condenser and TGTU catalyst activity. Heat transfer issues around the final seal leg in the larger 75-long-tpd sulfur plant led to a decision to raise the final condenser temperature to 290°F–300°F (143.33°C–148.89°C) in June 2021. Shortly after raising the temperature, refinery personnel noticed that the top of the TGTU hydrogenation catalyst bed activity started dropping, while the middle of the catalyst bed increased (**FIG. 5**). Total catalyst activity—in terms of ΔT—remained the same (**FIG. 5**).

Phillips 66 interpreted this catalyst behavior as sulfur entrainment affecting catalyst bed performance. Sulfur hydrogenation is a slower reaction vs. other reactions that occur in the tail gas catalyst bed, and, consequently, the bulk of the tail gas reactor exotherm has been shifted lower in the bed. There was no change in emissions associated with the changing ΔT in the tail gas catalyst bed.

SRU troubleshooting efforts began before laboratory results of the TGTU amine analysis were obtained. While SRU issues contributed to overall SRU/TGTU performance, SRU issues were not the root cause of the foaming issues.

Amine regenerator tray rating. Phillips 66 fractionation experts rated the amine regenerator stripping trays at typical operating rates prior to the foaming events. Jet flood ranged from 41%–63% as the system factor was varied from 1

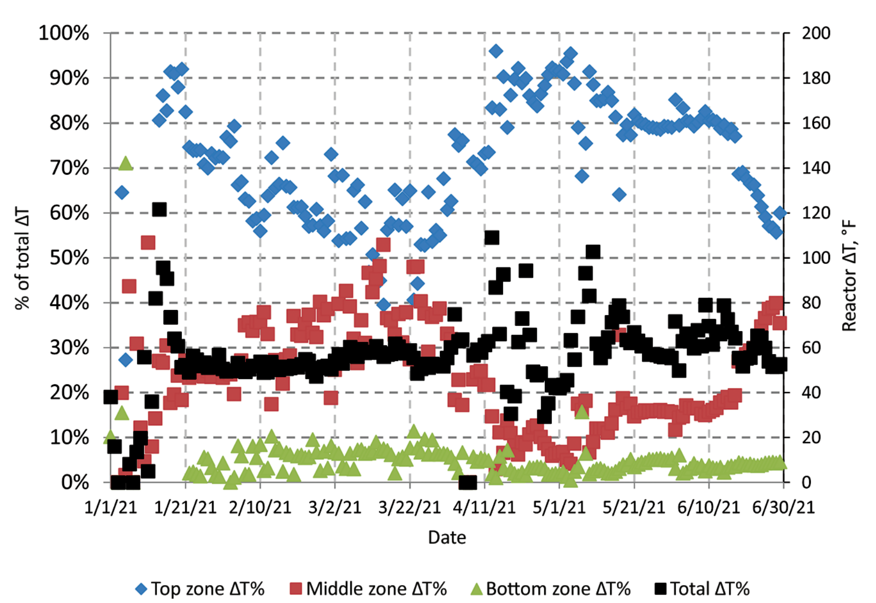

FIG. 5. TGTU reactor zone's ΔT% and total ΔT (°F).

to 0.65. Downcomer flood ranged from 42%–64% for the same range of system factors. The trays were not believed to be flooding. Dry tray pressure drop was greater than 1 in. H_2O, which is above typical weeping limits.

The stripping trays have positive downcomer clearance and were running slightly above the weir loading where unsealing has been observed. The trays were not believed to be operating in the spray regime.

Activated carbon beds and iron sulfide removal. Amine samples taken during a foaming event were sent to the Phillips 66 lab in Bartlesville, Oklahoma. The samples were dark green to blue in color (**FIG. 6**), and the refinery wanted to determine whether the foaming was related to either: 1) reformer hydrogen used for the tail gas catalyst that could have aromatics in it, or 2) the presence of polysulfides that amine vendors have stated could be formed from the reaction of sulfur dioxide (SO_2) and tail-gas amine. The amine turned this color again, even though its color had previously been markedly improved by using the unit's rich amine particulate filters. The Phillips 66 Bartlesville lab showed conclusively that the emerald green color was due to the presence of extremely small colloidal iron sulfide particles. After acidifying the amine, the iron sulfide dissolved, and the color disappeared from the solution (**FIG. 6**).

The Bartlesville lab passed the amine solution through small 0.45-micron filters, a smaller-than-practical field filter element. The 0.45-micron filters were ineffective at removing the color-producing particles. The lab then tested activated carbon as a filter media, and it was found to be effective (**FIG. 7**). The lab ran foam tests, using air as the process gas. The refinery amine showed a higher foam column *before* passing through activated carbon, rather than *after* passing through it (**FIG. 8**). Both color and foaming propensity concerns were mitigated after passing the amine through activated carbon. The authors believe that the foaming propensity was reduced because the activated carbon was removing organic compounds, such as surfactants that contribute to foaming. Further, the authors believe that the activated carbon removed the colloidal iron sulfide particles, thereby reducing the stability of any foam that was formed.

To make optimum use of the carbon bed as an iron sulfide filtration device, the carbon vendor was asked if there were any limits on amine circulation through the carbon bed. The recommended practice per the vendor was 2 gpm/ft^2 to 4 gpm/ft^2 for amine flow through the carbon bed, with a minimum contact time of 15 min. Based on that feedback, amine flow through the carbon bed was limited to about 28 gpm, which corresponded to a contact time of about 24 min. Flowrates higher than 28 gpm would reduce the efficiency of the carbon bed for iron sulfide removal.

Root cause of foaming. A graphical representation of the results of a comprehensive two-dimensional gas chromatography-mass spectrometry analysis of the refinery tail gas amine is shown in **FIG. 9.** The results indicated the presence of thianes, which are sometimes called "organic polysulfides," and the presences of fatty acids, including palmitic and stearic acids. The fatty acids are foam-producing agents commonly used in commercial soaps. Fatty acids react with a base, such as caustic or an amine forming a fatty acid salt, which, by definition, is a soap or surfactant. Therefore, the presence of fatty acids in an amine system is expected to cause foaming. Most likely, these fatty acids came from machining or lubricating oils used in metal-fabrication processes. The authors believe that these fatty acids are the root cause of the foaming and that thiane compounds are not surface-active agents and are not responsible for the foaming. No inorganic polysulfides were found.

Phillips 66 checked with the vendor that preactivated the catalyst with a proprietary process[a]. This process uses H_2S, hydrogen and heat in a vapor phase to sulfide the catalyst. It does not have any polysulfides in the process, per vendor feedback. At this time, the authors do not know where the thianes originated. A hypothesis is that the amine samples were shipped to the Bartlesville lab without a nitrogen blanket. Oxygen in the air mixed with H_2S in the amine due to high lean loading may have resulted in thiane production; however, this hypothesis has not been verified.

Antifoam. Based on laboratory tests, a vendor-supplied polyglycol antifoam

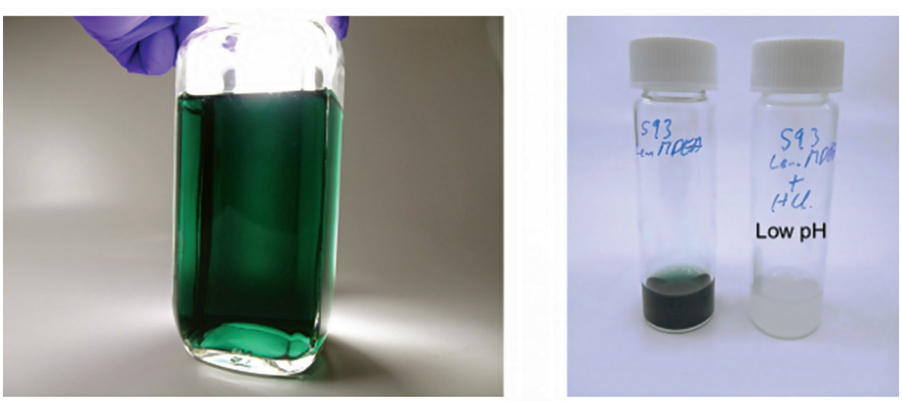

FIG. 6. Samples of amine taken during a foaming event. The samples were dark green to blue in color (left). After acidifying the amine, the iron sulfide dissolved, and the color disappeared from the solution (right).

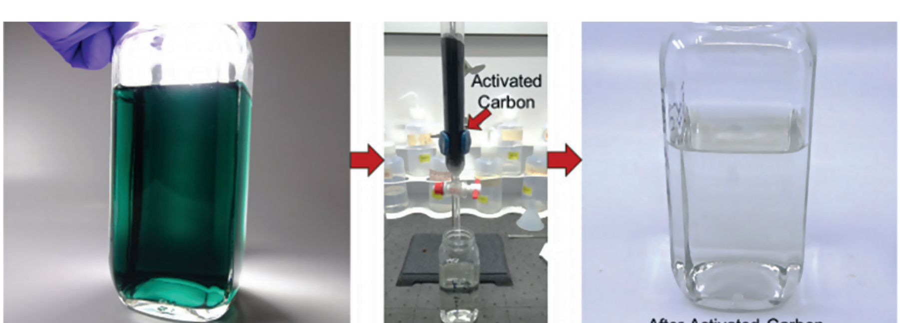

FIG. 7. Removal of amine color with activated carbon.

was effective in this case. Unfortunately, the unit was not built with antifoam injection facilities that would allow antifoam injection directly into the amine regenerator where the foaming problems were manifesting. The only as-built antifoam injection point was directed into the amine absorber, a packed column where foam is less likely to occur than in the trayed regenerator. Any antifoam injected into the absorber would have to pass through the activated carbon beds, where it would be adsorbed before getting into the trayed regenerator. Consequently, the refinery had to build a new antifoam injection facility that allowed antifoam injection into the regenerator reflux piping. The antifoam was effective when used at this location.

The unit engineer contacted the carbon vendor and verified that the activated charcoal used in the unit[b] will adsorb polypropylene glycol antifoam. Simple shake tests indicated that the amine was foaming more on the outlet of the activated carbon bed than on the inlet of the carbon bed, which indicated that the carbon bed was completely spent at times and needed to be changed out. It is also possible that the activated carbon was removing the antifoam and preventing its access to the regenerator. The unit engineers changed out the activated carbon to a fresh bed prior to the next startup.

TABLE 1. IC analysis of the amine sample

Ions, μg/mL	593-102 TGT lean MDEA
Sodium	1.6
Ammonium	5.6
2-methylaminoethanol	586.9
MDEA	130,539.7
Diethanolamine	1,685.1
Chloride	31.7
Nitrate	< 0.1
Phosphate	< 0.1
Sulfate	**894.6**
Sulfite	**535.6**
Thiocyanate	< 0.1
Thiosulfate	**1,503.4**
Acetate	< 0.1
Formate	76.9
Sulfide	4,107.7
Carbonate	1,715.2

Ion chromatography. IC results from a sample of lean TGT amine are shown in **TABLE 1.** Thiosulfate, sulfite and sulfate are present at noticeable levels. These data were initially interpreted as the results of an SO_2 breakthrough, which could explain the green amine, since SO_2 is corrosive in amine. However, the sulfide content was very high for tail gas MDEA (4,107 ppmw). High sulfide content means that the lean H_2S loading of the sample is high. This sulfide content or lean loading is so high that it would explain any stack emissions issues encountered at this unit. When lean (or rich) amine loading is high, thiosulfates, sulfites and sulfates are very likely to be generated by oxygen in the sample bottles contacting the amine solution and reacting with the sulfides. Based on this IC result, there was no reason to focus on SO_2 breakthroughs. The focus was put on amine regenerator operation to reduce the lean loading of the amine. It is most plausible that much of the color and iron sulfide in the amine resulted from inadequate regeneration, leading to high HS^- concentrations in the amine contacting the hot section of the amine plant that has carbon-steel components.

Another reason to strip the amine adequately in the regenerator is to remove heavy hydrocarbons that might accumulate in the tail-gas amine. The source of hydrogen in this refinery is reformer hydrogen that can contain small amounts of aromatic hydrocarbons. Maintaining adequate tail gas regenerator overhead temperatures [> 115.56°C (> 240°F)]

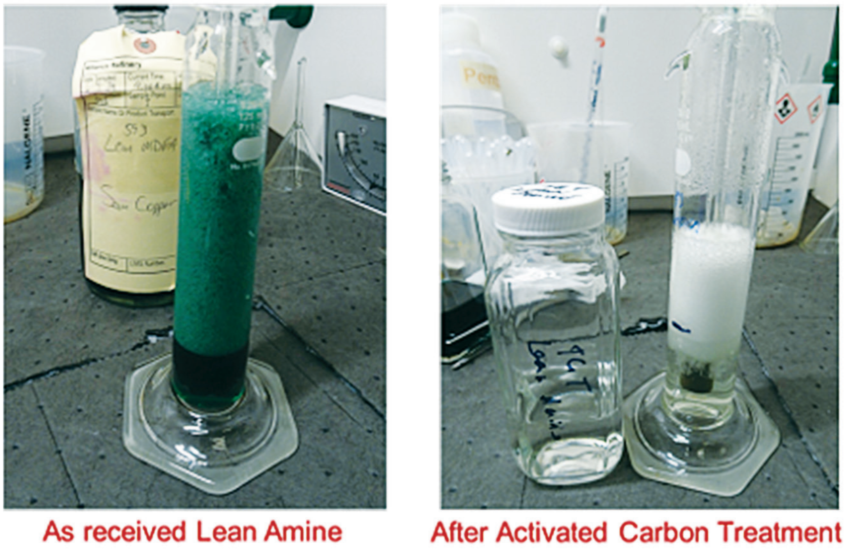

FIG. 8. Foaming propensity test.

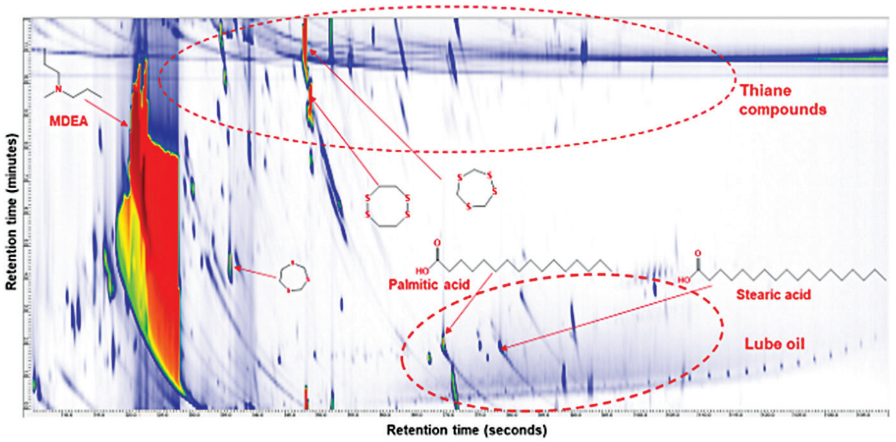

FIG. 9. A graphical representation of the results of a comprehensive two-dimensional gas chromatography-mass spectrometry analysis of the refinery tail gas amine.

can only assist in removing hydrocarbons from the amine. Engineering staff also made the decision to continuously purge 2 gpm from the reflux accumulator as a method to continuously remove hydrocarbons and other foaming species from the amine.

Reflux accumulator sizing. The reflux drum is a horizontal 2 ft-diameter drum, which was not overly effective at stopping foam once it rolled out of the column. There is a roughly 9-ft^2 area for gravity-assisted vertical separation in the regenerator upstream flowing into a horizontal 2-ft piece of pipe for the reflux drum. With the reflux drum operated half full, there is roughly 1.5 ft^2 of flow area, and gravity is working at a 90° angle to the gas flow. Foaming event mitigation was not considered in the design of the tail gas unit, but this should be considered for future Phillips 66 designs. The tail gas reflux drum does not include a hydrocarbon skim.

Summary of operating improvements. After these collective learnings, several improvements were implemented at the refinery, including:

- Increasing steam to the reboiler to target 120°C (248°F) on regenerator overhead. This move was made to decrease lean loading in amine, reduce iron-sulfide particle generation, and decrease H_2S vapor pressure over the lean amine to reduce stack SO_2 emissions.
- Adding antifoam injection points, so that antifoam does not have to pass through carbon beds and extra piping and equipment in the rich amine before entering the regenerator.
- Reducing amine circulation through carbon filters, so that amine flow was within design rates. Carbon filters for the new TGTU were installed on the rich amine piping. Carbon can be used to remove contaminants that cause foaming (e.g., fatty acids), and it can also remove submicron iron-sulfide particles, per Phillips 66 lab measurements.
- Establishing a constant purge rate of 2 gpm from the amine regenerator overhead accumulator to remove contaminants from the system. The purge rate helps to remove heavy hydrocarbons that might accumulate otherwise, due to their influx from the reformer hydrogen.

Takeaways. The following are the primary takeaway points from the investigation of foaming in the TGTU:

- The root cause of the foaming was identified from the lab measurements as fatty acids from rust inhibitors or metalworking additives. The authors believe that iron sulfide particles were acting to stabilize foam in the regenerator. Removal of the iron sulfide particles, along with fatty acids, has mitigated foaming considerably. The removal of only iron sulfide may reduce foam stability, but it is not the root cause of foaming itself. The MDEA still needs a foaming agent—in this case, fatty acids—to exhibit the foaming shown.
- New equipment in amine service should be rinsed with alkaline material to remove lubricants from the new equipment. Operating companies have recommended low-strength caustic (< 10 wt% NaOH) for years. The amine columns were only rinsed with hot condensate before this startup.
- Reducing steam to the amine regenerator reboiler to mitigate foamovers or "burping" liquid overhead can be worse than the foaming itself. Improperly regenerated amine can lead to emissions excursions, just as foaming does. Phillips 66 has found that operating tail gas amine regenerators with a target overhead temperature of 118.33°C–121.11°C (245°F–250°F) is a reliable way to control contaminants that lead to foaming in tail gas amine regenerators.
- Antifoam injection facilities must be provided to both absorbers and regenerators, as antifoam should not have to travel through an activated carbon bed to reach a column.
- It is not clear what advantage having a trayed regenerator vs. a packed regenerator provides in a tail gas unit, especially when the column diameter is only 3 ft. Phillips 66's operational experience has been that a trayed regenerator is more likely to foam than the packed regenerator. Industry experts suggest that packed towers can reduce the likelihood of foaming in the tail gas regenerator, provided there is proper liquid distribution. One further consideration is that, with large amounts of colloidal iron sulfide particles present, it is possible that packing would foul quickly, resulting in reduced separation efficiency in a packed amine regenerator.
- Activated carbon beds can be used to remove submicron colloidal iron sulfide particles. Although this is not desirable to the hydrocarbon removal capacity of the carbon beds, it is an effective stop-gap measure that can be considered to help preserve amine inventory. HP

NOTES

[a] Eurecat's TOTSUCAT process
[b] Calgon Carbon Corp.'s Sorbamine, AT 4x10

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A new era of turbomachinery reverse engineering

Engineering is all about solving problems with efficient solutions by designing and building various technologies and techniques.

In the oil and gas segment and hydrocarbon processing industry (HPI), one of the main challenges is how to maintain aging facilities with old equipment that have no existing original equipment manufacturer (OEM) and spare parts. To overcome this challenge, the author's company approved reverse engineering as a new methodology to repair obsolete equipment and ensure the availability of their spare parts.

Reverse engineering is the process by which a mechanical component can be modeled by evaluating its mechanical and performance characteristics, and its physical dimensions measured to produce a duplicate or an enhanced version of the component. In addition, utilization of reverse engineering methodology is mainly considered in the following cases:

- The OEM no longer exists.
- The product performance and features require improvement.
- The OEM is quoting an inflated price.
- The OEM is offering an unacceptable delivery time.

Problem identification. The story of reverse engineering at Aramco's Abqaiq Plants began when a single-stage steam turbine that drives a critical crude oil transfer pump was reported for a sudden increase in vibration values while the turbine was running on full load speed, as shown in **FIG. 1.**

By studying equipment parameter trends, the vibration analysis showed signs of rotor unbalance, which was later confirmed by performing an internal inspection of the turbine's rotor wheel by a state-of-the-art industrial borescope camera.

The equipment was sent to the company's mechanical services shop in Dhahran for a complete overhaul. After dismantling the equipment, the need to perform a complete re-blading activity to repair the rotor wheel was confirmed. Because the steam turbine was no longer produced and the manufacturer was no longer in the market, the limited availability of spares was one of the main challenges in bringing the equipment back to service.

During the spare parts material sourcing activities, a new rotor was offered by one of the main active steam turbine manufacturers with a cost of $350,000, which is equivalent to 70% of the cost of a new steam turbine. Furthermore, the delivery lead time of the new rotor was approximately 1 yr, which would result in increased equipment downtime, affecting overall plant availability.

Success story. In line with the author's company's efforts toward investing in new state-of-the-art technologies to enhance maintenance and reliability performance, Abqaiq Plants piloted the reverse engineering technology capitalizing on local resources and capabilities in collaboration with the company's central engineering and mechanical services shop. This action was taken to overcome critical equipment outages and minimize repair cost and time.

The reverse engineering process began with a 3D scan that was completed in-house using 7-axis scanning machines to capture the geometry of all parts in-house at the reverse engineering center.

The second stage was computer-aided design (CAD) modeling performed using the collected data during the 3D scanning stage. From this, the ultimate 3D CAD models for all required mechanical parts were developed and prepared by a highly advanced modeling software.

After that, the engineering work stage was started and involved significant R&D efforts. This project included more than 20 trials and experiments with different materials, geometries and heat treatment conditions to ensure the quality and mechanical integrity of newly engineered parts (**FIG. 2**). As a result, the strength of blades was doubled by upgrading their material composition.

The project was completed during the manufacturing stage when local capabilities were utilized for the blades fabrication in collaboration with one of the leading companies in the reverse engineering works in Saudi Arabia.

After this collaboration with Saudi Aramco departments, the steam turbine was returned to Abqaiq Plants, installed

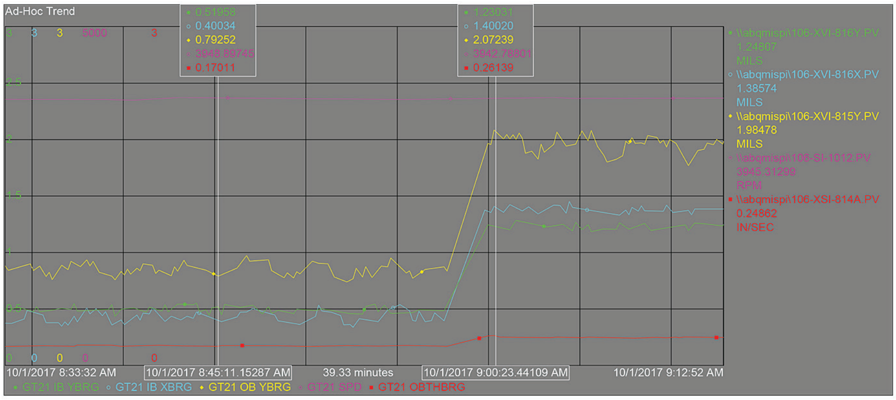

FIG. 1. Vibration parameter.

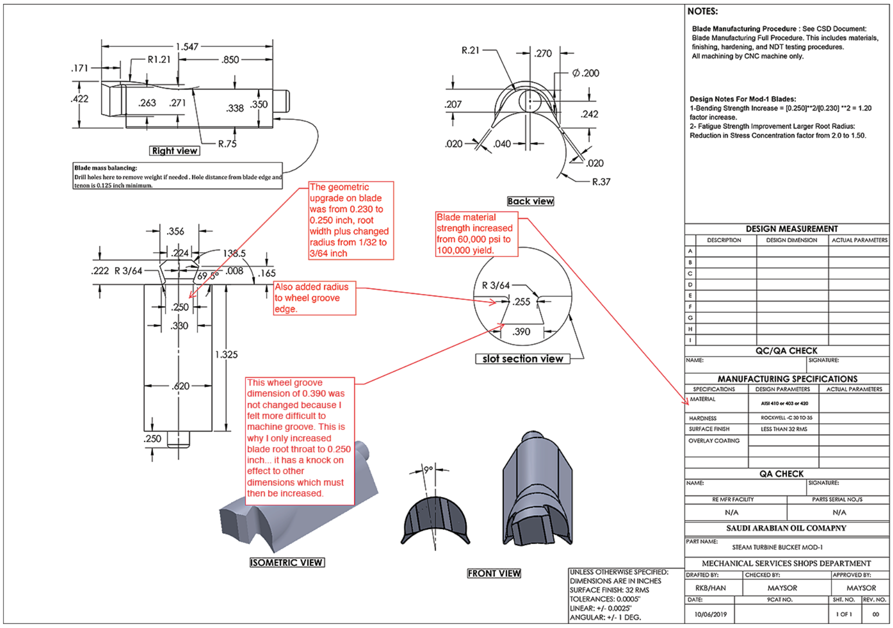

FIG. 2. Parts geometrics were one of the critical design requirements.

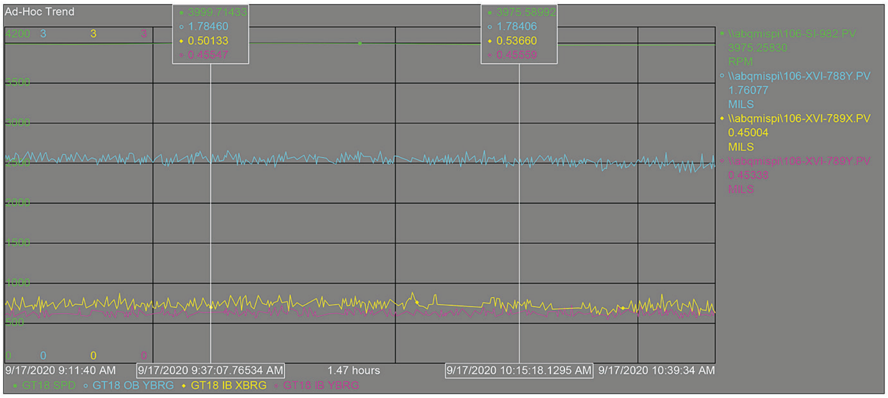

FIG. 3. Vibration readings are stable after the installation of new blades using reverse engineering.

onsite and successfully tested with normal and stable vibration readings, as shown in **FIG. 3.** The fabrication of the first steam turbine blades in Saudi Arabia and GCC was successfully completed with a total repair cost of only 15% of the new equipment that was offered.

Takeaway. Abqaiq Plants is expanding reverse engineering options as an effective solution to overcome the challenge of legacy equipment breakdowns, along with the upgrades and replacements program based on Abqaiq Plants' road map. Those new repair capabilities will also be expanded across Saudi Aramco on similar equipment, improving uptime and efficient business sustainability.

Utilizing reverse engineering presents a new opportunity for old and obsolete steam turbine repairs. Aging facilities can utilize and create less expensive and more efficient spare parts of obsolete equipment with higher quality and durability. HP

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Use straightforward troubleshooting and failure analysis to benefit the HPI

To operate reliably and profitably, oil refineries, petrochemical plants and gas processing facilities must avoid equipment failures. In the event such failures occur, the plant must find and remedy the root causes of these failures. Best-in-class facilities are reaching and maintaining this enviable status by pursuing repeatable failure analysis and troubleshooting (FA/TS). Guesses are rarely correct: they can lead to costly and even dangerous fixes. By their very nature, mere brainstorming sessions lack structure and timely, tangible results.

Experience shows that troubleshooting and failure analysis activities will terminate in only three possibilities:

- The failure cause is determined and removed from the inventory of future failure possibilities
- The failure cause is not found, and a recurrence is likely
- The failure cause is found but not disclosed to parties interested in doing anything about it.

Reliability professionals agree that discovery and permanent remedial action of the true root cause of a failure is the only correct course of action. These reliability-focused professionals will readily agree that inaccurate troubleshooting leads to incorrect conclusions and wasted time. Because the analyst or troubleshooter is under pressure to *do something*, tinkering at the fringes of procedural changes or design modifications is quite common. Moreover, hiding behind claims that a failure is an "act of God" is common, albeit inappropriate. The Almighty may permit that a city built below sea level is damaged by a flood after the levies break and the pumps fail, but the Almighty did not ask the people to build substandard levies and flawed pumping equipment. The chain of events always originates or leads to decisions and indecisions, actions and/or inaction by humans who, finally, are nowhere near as perfect as they would have us believe.

Reasons to improve troubleshooting methods. Of course, nothing devised by man is perfect, nor will it ever be. Problems of one kind or another will always exist. In other words, troubles must be identified and remedied. Regrettably, troubleshooting is usually done after a problem surfaces. Suppose there was a time when the sugar cane crop failed, and the landowner attributed the problem to the sugar cane worm. Since pesticides had not yet been invented, he countered the threat with imported beetles that ate sugar cane worms. When the beetles took over, he imported ugly beetle-eating toads which, unbeknownst to him, preferred to decimate his previously profitable tobacco leaf crop. This made him decide to import Genovese disease-carrying rats as the cure. These rats failed to do the job, but by the time he considered red foxes as the problem solvers, he realized that the red fox recommendation came from gentrified landowners whose ulterior motive was nothing but hunting foxes.

While some of the above is indeed a bit far-fetched, there is also a measure of truth in it. It pays to consider the message: Do not tackle serious problems with temporary fixes. Recommend solutions that are backed up by both data and science. Try not to endorse remedies that have unintended consequences or run counter to the satisfactory experience record of others. Therefore, investigate or pay attention to others and try to learn from them.

A few fundamental facts are usually recognized and accepted by the leaders of modern industry: inadequate troubleshooting leads to higher costs, wasted time and makes the company's troubleshooting team look unprofessional. Because we, the co-authors, have made our living as troubleshooters, allow us to make use of these facts in demonstrating simple examples of solving randomly occurring process pump problems that can be tackled by using course content that combines[1] several proven approaches[a].

THE SEVEN ROOT-CAUSE FAILURE ANALYSIS

Collecting a large failure mode inventory while realizing that such an inventory will differ for different machines and their components makes considerable sense. Examining this inventory and conducting a structured review of data observed during and after a failure makes it possible to draw conclusions as to the failure's origin. The reviewer or failure analyst should concentrate on deviations from proper design, component function, appropriate coatings, and many other factors.

However, generalities that lead to a so-called "shotgun approach" must be avoided. In shotgun-style failure analysis and troubleshooting, much time is often wasted on debates that lack both focus and value. There will then be a trend towards verbalizing scenarios that are a mix of the probable and highly improbable, the reasonable and unreasonable, the often observed and perhaps things that have never happened since Leonardo sketched a helicopter for tentative future use by Igor Sikorsky. Do not disregard everything that happened in the 440-yr span between those two inventors. Nev-

ertheless, accept our premise that we need focus and must concentrate on realistic events and solutions.

To begin, we observe that work execution requires emphasis on any two of the three attributes shown in **FIG. 1.** If a manager demands quality work done cheaply and quickly, we must tactfully train that manager to let us know which two will be accepted, since achieving all three will be impossible. Frankly, it is in everybody's best interest that our work output be good. That leaves it to the manager to accept that *good* is your unyielding standard, but he/she may instruct you to either be *fast* (and expensive) or *cheap* (and slow, by prevailing standards).

In this context, a useful focus is readily obtained by accepting that all machinery failures, be they turbo-compressors or machines making cotton-tipped ointment applicators or doorknobs, will experience distress attributable to only one of seven possible categories:[1]

1. Design deficiencies
2. Material defects
3. Processing and manufacturing deficiencies
4. Assembly errors
5. Off-design or unintended service conditions
6. Maintenance deficiencies (neglect, procedures)
7. Improper operation.

Of equal importance is recognizing that the basic agents of machinery component and parts failure mechanisms are always force, a reactive environment, time and temperature (FRETT). Each of these four can be further subdivided into steady, transient, cyclic or durations labeled very short, average length, long and so forth.

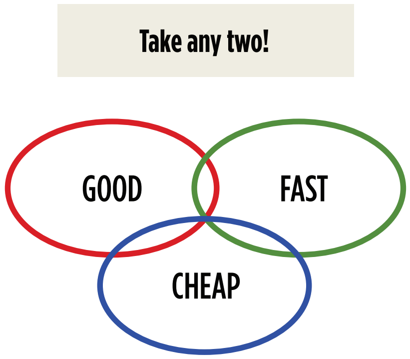

FIG. 1. Good managers know that competent staffers will give their employer any two of these three. One of these three attributes will be unachievable.

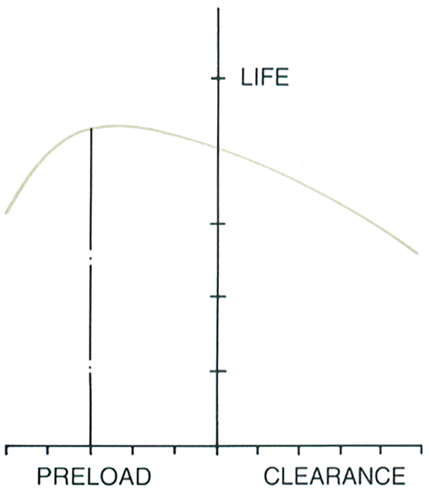

FIG. 2. Effect of preload on bearing life.[1]

The gasket case.

An expert failure investigator will take pleasure in reaffirming the above by stating that regardless of whether the component is made of plastic, steel, rosewood or porcelain, when it breaks the basic agents of failure mechanisms are found in FRETT, and FRETT alone. Once this fact is accepted, we have a starting point for investigating our first example, a leaking gasket. Looking at the data, it will not be difficult to determine which of these four basic agents can be crossed off our list. If only 6 wk had elapsed since the gasket was inserted between a pump discharge nozzle and its adjacent pipe flange, it would be safe to delete "time" from the acronym FRETT.

FIG. 3. The oil ring on the right ran "downhill" and contacted a stationary part. Abraded bronze particles contaminated the lubricant and caused short bearing life.

Suppose the remaining five gaskets in the various flanges associated with the downstream discharge piping had been in service for close to 4 yr and were of the same material composition as the leaking gasket. In that case, we might cross off both "reactive environment" and an abnormal operating "temperature." That would then leave us with "force."

Clamping forces are a function of bolting torques and bolting procedures, bolt sizes, fabrication methods, hardness and bolt materials. All of these must harmonize with well-established guidelines—failures will result when we deviate from, or disregard, established procedures. If we allow several deviations to exist at the same time, failures become a certainty. Data relating to bolt size, material, gasket deformation, flange condition, method and sequence of bolt tightening will lay bare the cause of gasket leakage. Of course, the human factor remains. If the two workers working on that flange were denied necessary tools or time, we can state that the case of the leaking gasket may have its roots in a measure of somebody's flawed thinking.

The case of the overheated bearing.

Our second example involves a pump bearing that showed signs of temperature-related failure. We must resist the temptation to say that the "bearing failed, therefore the bearing is at fault." Instead, we might carefully look at failure frequency and failure record. If the pump manufacturer has used 600,000 identical bearings in 300,000 pumps of the same model designation, we have no reason to re-engineer the pump for a larger bearing.

As we then look at the seven possible failure cause categories, we should cross off numbers 1, 2, 4, 5, 6 and 7. We look more closely at (3), "processing and manufacturing deficiencies." If the shaft was to be 75-mm diameter with a plus-tolerance of 0.02 mm–0.03 mm but we carefully measure and record 75.04 mm, and the bearing bore was to be 74.99 mm with a minus tolerance of 0.01 mm–0.02 mm but is measuring 74.96 mm, there will be an interference fit of 0.08 mm (0.003 in.).

According to the trend curve in **FIG. 2,** such an interference fit will cause bearing operation deep in the high-preload range

where high bearing temperatures and short life are certain to exist. Excessive preload will also exist if all tolerances are in the center of their permitted ranges, but the shaft material is a type of stainless steel that thermally expands up to 17% greater than that of the tool steels normally used in pump shafts.[2]

Hopefully, we also investigate the condition of our oil rings (**FIG. 3**), which, should be concentric within 0.002 in. (0.05 mm).[2] To stay within these recommended tolerances, oil rings must be heat-stabilized. So as not to run downhill and abrade as in **FIG. 3,** oil rings cannot be allowed on shafts that are out-of-horizontal. Both shaft alignment and horizontality must be near-perfect. If a lubricant is thicker than allowed, the oil ring may simply not feed enough oil into the bearings.

Whenever two or more deviations combine, failures are likely to become more serious. We have seen two oil rings [a maximum allowable eccentricity of 0.002 in. (0.05 mm)] with eccentricities of 0.017 in. (0.43 mm) and 0.061 in. (1.55 mm), respectively. We have also come across bearing housings with oil rings designed to operate in ISO VG 32 lubricants but barely capable of operating while immersed in an ISO VG 100 lubricant. Repeat malfunctions were tolerated and were soon accepted as the norm. The reasons for inflated maintenance budgets and random downtime events should have been evident to experienced observers.

In the event of equipment failures, process facilities must find and remedy the root causes by pursuing repeatable failure analysis and troubleshooting. Guesses are rarely correct: they can lead to costly and even dangerous fixes.

The case of the missing drain holes. For good measure, our third example again involves an overheated pump bearing and indications of black matter floating in the lubricant. **FIG. 4** helps us understand one additional and often considered "elusive" reason for bearing distress. Access to a cross-section view was available in this instance and facilitated finding the likely cause of overheating. It was noted that oil could collect near the outboard sides of the two bearings in **FIG. 4.** The pump manufacturer forgot to drill a drain passage for the oil trapped behind each bearing.

Since there were no drain holes, it could be reasoned that trapped oil turning to viscous tar or solid coke contributed to the early bearing distress reported by one of the manufacturer's Canadian customers. When this was brought to the atten-

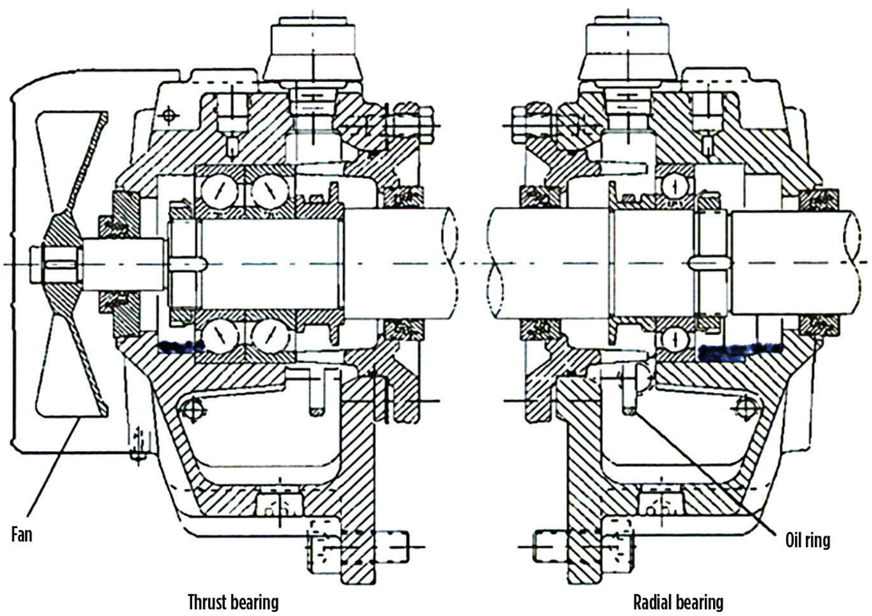

FIG. 4. OEM drawing of bearings with trapped oil. Drain holes are important.

tion of the pump manufacturer, we were told that, although the pump manufacturer had neglected to show drain holes, the shop always provided these drain holes. Well, as a wise and observant reliability manager in Texas City said in 1980, "When it is all said and done, more will have been said than done." That truism has been true for centuries and was correct in this instance. Accordingly, our recommendation is to trust, but verify. In the great majority of cases, not only is there more value in verifying than in trusting, but it will also cost less.

Experience-based training courses will add value. Whenever failure analysis and troubleshooting are called for, the trained analyst insists on collecting failed parts, measuring and recording dimensions, and run-outs of rotating components. Suspicious wear patterns should be photographed.

The above examples represent details of closely monitored parts, both new and failed or defective. Thorough analysis is especially important when there is evidence of bearing overheating. Contributing and causal factors can be of great importance and will require both technical knowledge and the application of structured analysis. A formal training course in systematic failure analysis[a] will go a long way towards uncovering and eliminating costly repeat failures. Downtime is prevented and money will be saved by learning (and later implementing) tested approaches that bring the right focus to modern equipment troubleshooting.

Indeed, the culmination of equipment failure analysis involves motivated course attendees. An experienced instructor will assist them as they contribute to very comprehensive custom troubleshooting tables. The content of these tables represents an expansion of the original equipment manufacturers' (OEMs') tables into territory that the OEMs may have overlooked for years. We know of instances where vendors viewed expanded troubleshooting tables and/or the use of oil mist lubrication as the original sin, a "sin" resulting in shrinking spare parts sales. We, however, cling to the belief that good marketing decisions may result in unusually reliable pumps and other fluid machines that capture premium profits and enhance vendor reputations. We believe that a good reputation will more than make up for reduced spare parts sales.

From the "5 Whys" to modern methods of failure analysis. The "5 Whys" method of defining failure causes predates the training course in systematic failure analysis[a] by several decades; however, suppose it had been attempted in one of our earlier examples involving a failed pump bearing. The analyst would have started by asking: Why did the bearing fail? Chances are that someone offered an answer involving the lubricant (e.g., perhaps not enough oil). Why was there insufficient oil? Was it because the constant level lubricator had not been refilled?

We will never know how the next "Why" would have been phrased, so we will leave it at that. We would venture to guess that "slightly off-horizontal shaft centerline," "oil ring eccentricity outside allowable range," and "OEM design allowed oil to get trapped behind thrust bearing," would not be listed as likely root causes.

Modern and consistently effective methods will be needed to achieve the goal of optimally conducting best available troubleshooting and failure analysis in today's highly competitive work environment. Investigate them and invest in the best. HP

NOTES

[a] Equifactor®

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Mechanical impact of rerating process equipment

Process equipment operating in a brownfield environment is often rerated pertaining to the changes in process parameters during debottlenecking. Rerating, with regard to process equipment, means redesigning the equipment to adhere to new rerated conditions.

Often, the design pressure and design temperatures are increased, and the equipment must be reevaluated for more severe design conditions—this is known as uprating. It is very important to reverify the mechanical design of the existing equipment to meet the new rerated conditions. Most of the existing equipment would be nearing the end of its life, and the impact of corrosion over the years would, most likely, be substantial. Therefore, it is necessary to reevaluate whether the equipment has sufficient corrosion allowance until the next inspection or whether the equipment should be retired from service. Rerating existing equipment can be cost effective vs. purchasing new equipment.

The author has been involved in many rerating studies to check the mechanical design adequacy for existing equipment. The following are important considerations when reverifying the mechanical design for process equipment.

Existing equipment drawings. Before starting any design verification, it is important to have existing drawings of the equipment. It is often noticed that there will be a lack of existing documentation. At times, only general arrangement drawings will be available and detailed drawings may be missing, or vice versa. Make sure you have legible copies of drawings. A good place to start is looking at the final data book for the equipment submitted by the original manufacturer, if available. However, for older equipment, data books may not be available. Any subsequent revisions, modification drawings by the same or different manufacturer, or marked-up drawings must be traced out, as they can provide vital information.

Once the relevant drawings are obtained, review them meticulously to understand the modifications that have been made on the equipment chronologically, along with the present status of the equipment. Try to obtain any other available documents, such as the original manufacturer's design calculations, inspection documents, material certificates, the manufacturer's data reports and/or previous equipment inspection reports. All of these documents will eventually contribute significantly to understanding and finalizing the rerating study.

Site visit/interaction with operations personnel. Once you are familiar with the drawings, conduct a site visit with the operations personnel in charge of the area. Physically see where in the plant the equipment is located to verify that the equipment matches the drawings. Operations team members should know much more about the equipment than other personnel, and they will be helpful in clarifying the missing links that may not appear on drawings. Record all information provided by the operations personnel.

Since this is an important step at the beginning of the process, it is suggested to go to the site with a fresh copy of existing drawings, and to mark up any visible ambiguities on the drawings. For example, if an additional nozzle is shown on the equipment, mark it on your drawing copy. Every intricate detail visible on the equipment should be marked up on your copy and clarified with the operations personnel. This exercise will help to understand chronological changes in the equipment.

Engaging the inspection team or third-party inspectors. Conduct a meeting with the onsite inspection team or have a third-party inspection company carry out the equipment inspection. Share all the information available, along with marked-up copies. Highlight all the ambiguities found during the site visit, record them, and make a meeting log, as this will help to obtain more accurate results during the actual inspection of the equipment. Accurate thickness checks should be done using available advanced technology (e.g., infrared checks) to determine shell thinning, and to inspect heads, nozzles and other pressure-retaining parts. This is equally important for supports and external attachments. Photographs of internal areas and external parts should be included in the inspection report for additional clarity. The inspection report should be prepared comprehensively and should clearly mention the areas of concerns found by the inspector.

Inspection report and rerating process conditions. After receiving the inspection report, review it carefully and check for any points that can potentially derail the design reverification process. Anything abnormal on the inspection report should be discussed with the owner and sorted out prior to commencing the design reverification activity. Ensure that the rerating process conditions are available for each piece of equipment.

Sometimes, there will be fluctuating process parameters, such as temperature and pressure. In such cases, check to see if the owner can provide the complete table with the corresponding values relevant to that equipment. Since the allowable stresses change with temperature, it is important to have this table to determine the required thickness, as sometimes an odd combination of pressure and temperature can have detrimental effects on the equipment design.

Equipment modeling and design calculations. Equipment should be

designed for fully corroded conditions. **Note:** The factor of safety (FS) considered in the code for new materials is less vs. the FS for existing older equipment materials. This is primarily due to enhancements in materials and welding technology. This difference in FS is noticeable in the allowable stress value. Therefore, before starting calculations, it is important to change the allowable stress values in the design software used for analysis. Otherwise, by default, software uses allowable stress values as per the current FS. This can lead to a misinterpretation that the required thickness is sufficient for the rerate conditions, which otherwise would be failing when used with the earlier FS.

The full-scale model of the equipment must be created for the analysis being inputted into the rerated design conditions. A separate file must be created for the base case that indicates the existing design conditions, as well. This will provide leverage to understand how the rerated design case is different from the base case.

Rerate report. The rerate study should be properly documented to elaborate the findings. This report should be in an explicit format that is easy to understand for client/owner approval. A comprehensive rerate report should include the following:

- The base case (old) design conditions and rerated (new) design conditions should be compared and evaluated.
- The code used for rerating the equipment. Allowable stress values and joint efficiencies should be tabulated. Typically, when the rerated design pressure is less than the maximum allowable working pressure (MAWP) of the pressure vessel, and when the pressure vessel has been hydrotested to a pressure based on the MAWP, then the rerated equipment will be acceptable in most cases.
- The minimum required thicknesses vs. the existing thicknesses for each component affected by the rerate should be tabulated. Each value should be clearly indicated. For identification, components that are failing must be indicated in red or in different fonts. Additionally, for further identification of the components that are failing, footnotes can be added below the tables.
- Rerating shell-and-tube heat exchangers will be more complicated than vessels and columns, as there are some components in heat exchangers that are in contact with both the shell side and the tube side, and with the floating head and tubesheet. Therefore, when rerating shell-and-tube heat exchangers, personnel must check how the shell-side and tube-side conditions are affecting these components.
- The remaining life of each component and the required inspection interval determined by the rerate study should be tabulated. Instead of concluding that the equipment must be replaced when its corrosion allowance is consumed, it can be downrated to allow its continued use in a less-severe design condition. Such recommendations can be highlighted in the report for owner approval.
- Components requiring any physical modifications should also be clearly identified. If a hydro test must be carried out, test pressure and temperature must be mentioned. All the relevant attachments to the report—such as rerated design calculations, original manufacturer's calculations, drawings, the manufacturer's data reports and equipment inspection reports—should be included. Most importantly, revised and/or marked-up drawings, as well as new drawings for replacement components and rerated nameplates, must be included in the report.

Takeaway. Based on the rerating study and further meetings with the owner/stakeholders, one of the following recommendations can be concluded for equipment: use "as is," modify or replace. Modification or replacement can be initiated with a new requisition. HP

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Combating naphtha reflux section corrosion mechanism and production losses in a CDU

Corrosion is one of the most important challenges that refineries face (**FIG. 1**).[1] Sometimes, corrosion can cause the loss of production. Managing this issue in an optimal manner can mitigate or eliminate production loss due to maintenance shutdowns.

In refining process units, especially in the crude distillation unit (CDU), there are different kinds of corrosion. The primary corrosion problem facing the CDU is ammonium chloride and hydrochloric (HCl) acid corrosion, which is discussed in this article. Opportunities are always available to decrease or prevent these types of corrosion, either with additional investment or with operational changes.

The aim of the CDU is to remove salt and water in crude oil from the system, and to separate fuel gas, LPG, light naphtha, heavy naphtha, kerosene, light diesel, heavy diesel and atmospheric bottom fractions by taking advantage of the differences in boiling points. The separated fractions are sent to other process units in the refinery.

Crude oil fed to the unit is processed through four basic processes: preheating and desalting, atmospheric distillation and the reflux system, the naphtha splitter and debutanizer columns.

Charge pumps send the crude oil to the unit, where it is heated with the boiler feedwater to provide the desalter temperature. Then, crude oil passes through the first group of preheating exchangers and is heated with naphtha reflux, kerosene, light diesel, heavy diesel and atmospheric bottoms, respectively, to provide the optimum desalting temperature.

The crude oil mixed with washwater that is supplied to the desalter is then sent to the second group of heat exchangers after the desalting operation. The crude oil is sent from the desalter outlet and enters the second group of heat exchangers, where it is heated with kerosene reflux and atmospheric bottoms. Continuing from two branches, the crude oil enters the furnaces. The furnace outlet is charged to the atmospheric distillation column. Some heat is withdrawn from the column by reflux circulation to balance the heat loading along the column. The naphtha reflux stream heats the crude oil in the first group of heat exchangers and then cools and returns it to the column as reflux.

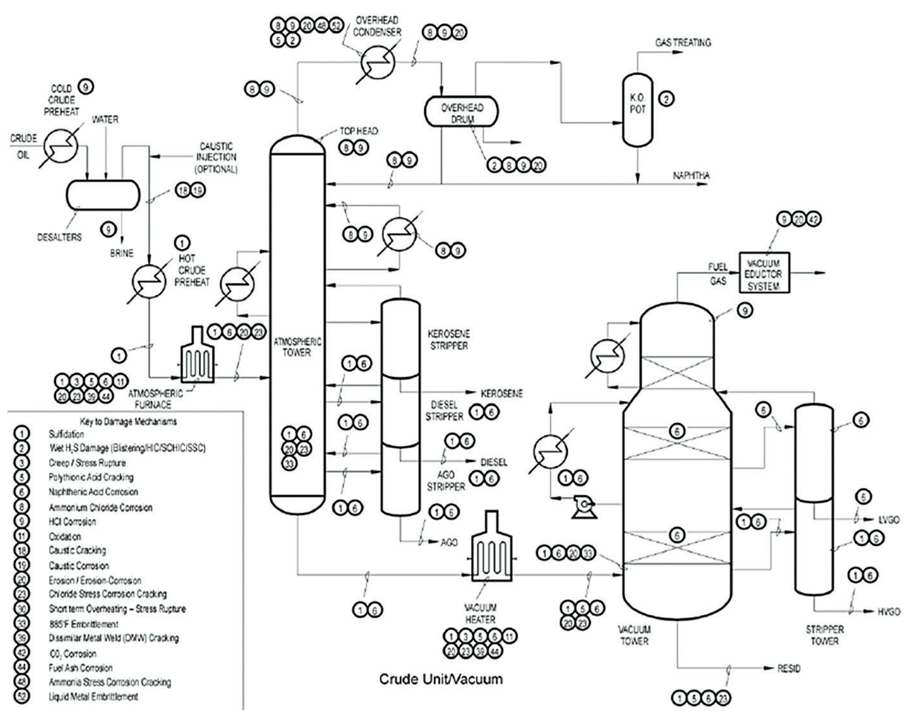

FIG. 1. Corrosion is one of the most important challenges that refineries face.[1]

The main corrosion mechanisms through the naphtha reflux section are ammonium chloride and HCl corrosion (**FIG. 2**). HCl corrosion occurs with dew-point corrosion if there is water vapor and HCl in the environment. When the water vapor condenses, it forms liquid drops with HCl, causing the material to be exposed to a solution with a very high HCl concentration and low pH. High existing acidity means high corrosion rates. Liquid HCl may form in the heat exchanger under the salts of ammonium chloride or amine hydrochloride.

Ammonium chloride is an acidic salt formed because of the combination of

gaseous HCl and ammonia. In the absence of water in the environment, it does not show corrosive properties; however, excessive accumulation may cause fouling problems. When the dewpoint temperature is lowered, it may form an aqueous acidic solution and cause corrosion at high rates, especially since the pH of the first water drop formed will be very low. The average ambient temperature is kept 20°C–30°C (68°F–86°F) above the condensation temperature.

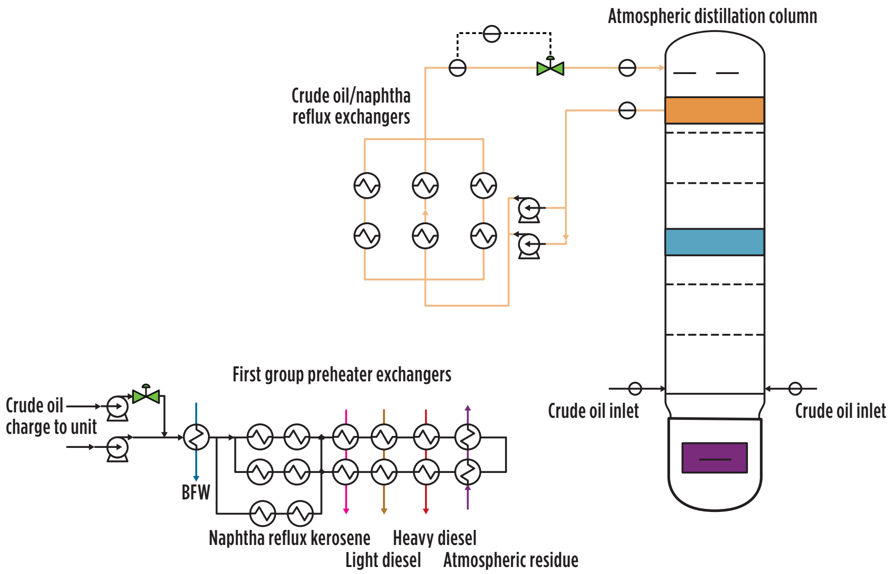

FIG. 2. The main corrosion mechanisms through the naphtha reflux section are ammonium chloride and HCl corrosion.

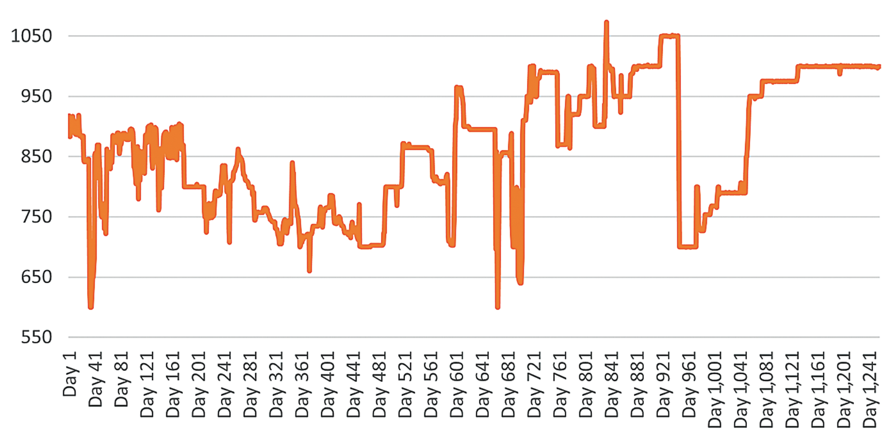

FIG. 3. Naphtha reflux flow rate, m^3/hr.

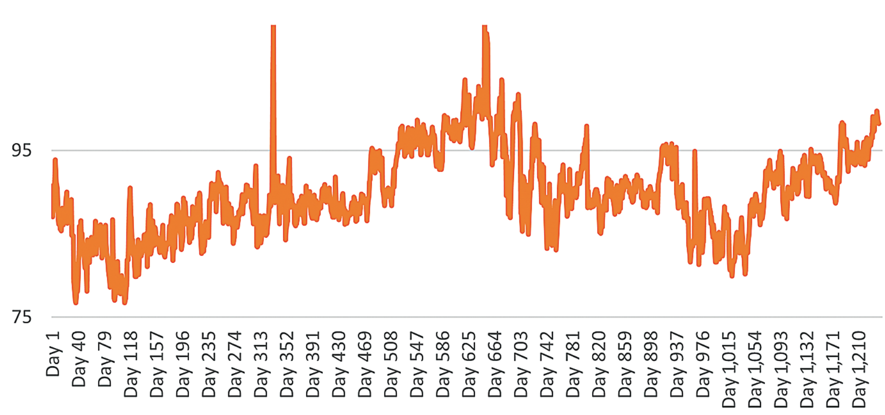

FIG. 4. Naphtha reflux return, °C.

To minimize the corrosion mechanisms, a corrosion inhibitor is injected into the reflux section. In terms of protection, pH values in the stream should be in the range of 6–8. If pH values are not in that range, then there can be exchanger tube leakage in the preheat train, naphtha reflux/crude oil exchanger.

If there is any tube leakage in the naphtha reflux exchanger, the kerosene product will be off-spec due to crude oil that penetrates the reflux stream. The primary cause of tube leakage is low pH (e.g., 2–3). If there are droplets of water in the naphtha reflux section, this will cause a dramatic decrease in pH and result in leakage. If liquid water droplets can be eliminated from the stream, the pH values will increase, and leakage will not occur or the leakage period will be longer than the previous operational period.

At a Tüpraş refinery, the leakage period was 6 mos–12 mos. The leakage was detected by the color of the kerosene product, with the root cause being a blockage in the exchanger group. This led to increased temperatures in the column's overhead section, leading to heavier light ends—especially in heavy naphtha—and an increase in offgas flow from the overhead drum.

The most effective way to overcome this challenge is upgrading material. However, this option is costly. A second option is to increase the pH value of the naphtha reflux stream by increasing the column return temperature of the reflux stream.

As shown in **FIGS. 3–5,** naphtha reflux pH values increased with the increase in naphtha reflux return temperature. To increase the temperature of the naphtha reflux stream, the reflux flowrate was increased from 700 m^3/hr to 1,000 m^3/hr. After this operation, the trend of pH tends to increase from 4–5 to 7–8. As shown in **FIGS. 3–5,** temperature is changing pH in an effective way. From the last leakage issue, the authors' company's refinery heat exchangers were in operation for nearly 3–4 times longer than the previous period. This means that there were no operational upsets and no maintenance issues. This also means that refining personnel

can increase unit reliability with little interventions and overcome corrosion issues with simple adjustments.

Results and discussion. If the configuration of a crude oil unit has a naphtha reflux section, the primary challenges are ammonium chloride and HCl corrosion. To mitigate or eliminate corrosion-related production losses, operational changes—such as increasing the reflux stream temperature—are ideal. If the stream temperature is 20°C–30°C (68°F–86°F) higher than the condensation temperature, then the corrosion mechanism will be reduced or prevented. In Tüpraş' case, the naphtha reflux return dewpoint value was 70°C (158°F), and the stream temperature increased by 25°C (77°F). After this operation, the pH tends to increase from 4–5 to 7–8. As a result, the possible exchanger failures were prevented, and the crude oil unit was able to stay in operation for 3–4 times longer vs. the previous operational period. This is an improvement achieved with no investment.

This article demonstrated that there are opportunities to minimize or prevent production losses, upsets, maintenance expenses and to increase operational availability and reliability via operational issues and without investments. HP

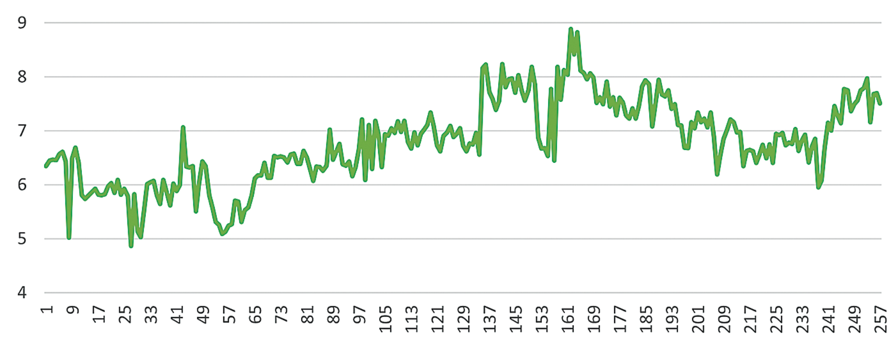

FIG. 5. Naphtha reflux pH.

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Make your gasoline more valuable with butane blending

Butane blending—blending butane into a finished gasoline with the goal of increasing the volume—is a well-known technique that has been used in the gasoline business for many years. Butane is injected because it is cheap (~$36/bbl) and due to its positive properties [high Reid vapor pressure (RVP) and high octane]. **Note:** Blend component prices herein are based on January 2022 data.

Due to favorable economics, blending butane and/or naphtha into commercial pipeline gasoline—i.e., (conventional gasoline) CG87 or CG93 to downgrade it to CBOB (conventional before oxygenate blend) regular or CBOB premium—is being considered.

Alternatively, bio-ethers such as ethyl tert-butyl ether (bio-ETBE) or methyl tert-butyl ether (bio-MTBE) can be blended. With the bio-fuels market anticipated to grow by ~40% in the next 10 yr, blending bio-oxygenates could prove to increase profits. Most of these bio-fuels are well used in Europe and Latin America, so why not invest more in the U.S.?

Case 1. **TABLE 1** shows the downgrading of a CG93 to CBOB A4 by injecting butane and naphtha, generating a profit of $0.92/bbl. In this example, 3.74 vol% of butane is being blended with naphtha on top of CG93 to produce CBOB A4. All specs are met with a profit of almost $1/bbl.

Case 2. **TABLE 2** shows the downgrading of a CG87 to CBOB A4 by injecting butane and naphtha, generating a profit of $3.7/bbl. In this example, 4.56 vol% of butane is being blended with naphtha (light and medium) on top of CG87 to produce CBOB A4. All specs are met with a profit of almost $4/bbl.

Both cases show that blending butane is a lucrative business.

Case 3. **TABLE 3** shows the downgrading of a CG87 to CBOB A4 by injecting butane and naphtha, and bio-ETBE, generating a profit of $ 0.77/bbl. The recipe to make CBOB A4 is shown in **TABLE 3,** using butane, naphtha, CG87 and bio-ETBE. All specs are met with a profit of $0.77/bbl.

How butanization works. Typical butanization levels vary from 1%–3%. Adding lower RVP naphtha lowers the CG93 RVP,

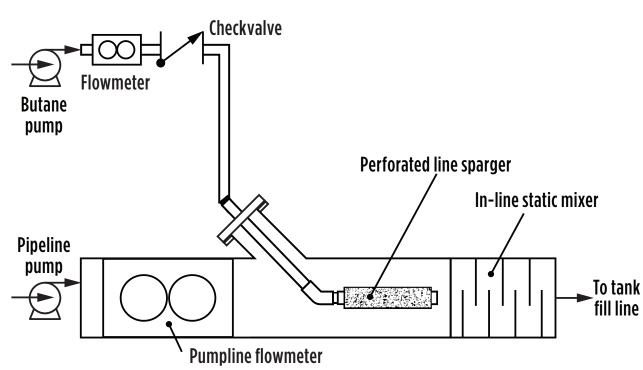

FIG. 1. Inline butane sparging blending.

TABLE 1. Downgrade CG93 to CBOB A4, with a profit of $0.92/bbl

	Recipe		Inventory, bbl			Price
Component	Vol%	bbl	Initial	Final	Remaining	$/bbl
n-Butane	3.74	3,500	0	100,000	96,500	50.51
Natural gasoline	0	0	0	100,000	100,000	76.38
Light naphtha	42.78	40,000	0	100,000	60,000	75.12
Medium naphtha	0	0	0	0	0	75.78
Heavy naphtha	0	0	0	0	0	76.44
MTBE	0	0	0	0	0	62.43
ETBE	0	0	0	0	0	91.34
CG87 reg	0	0	50,000	50,000	50,000	87.03
CG93	53.48	50,000	0	0	-50,000	92.15

making it possible to add even more butane for a total of 3%–10% additional volume increase over the CG93 volume, depending on the properties of blending butane and naphtha available.

The cheapest and fastest way to implement the butanization scheme is to inject butane into the tank filling line as the product is being pumped into the tank. The disadvantage is that the properties of the gasoline being pumped into the tank are not well known; therefore, the butanization amount will be conservative and not economically optimum.

The next cheapest way to implement the butanization scheme is to sequentially inject butane into the tank filling line after the gasoline product has been pumped into the tank. The advantage here is that a tank sample can be taken and its properties analyzed. This allows the determination of the maximum amount of butane that can be injected without throwing the gasoline product off spec. The disadvantage is that it takes much longer to sample and analyze the tank, do the butane injection calculations, physically add the butane, circulate the tank to ensure homogeneity, sample the tank again, and ensure it is on spec.

A final option is to implement an inline blender that simultaneously adds butane and naphtha to a stream of pipeline gasoline. By using an online analyzer measuring RVP and potentially other properties, operators can exploit every degree of freedom to maximize the injection of butane and naphtha while maintaining an on-spec blended product. Additionally, the use of an inline static mixer ensures the homogeneity of the blend, reducing or eliminating the time needed to circulate a tank for homogenization. The disadvantage is the higher cost of installation (approximately $500,000–$750,000).

BUTANE AND/OR NAPHTHA BLENDING SCHEMES

Injection of butane and/or naphtha into the tank fill line. Physically, butane and/or naphtha are injected via a specially designed sparger—a pipe with holes drilled in it—that sticks in the middle of the filling line (**FIG. 1**).

The butane and/or naphtha lines are each provided with

TABLE 2. Downgrade CG87 to CBOB A4, with a profit of $3.7/bbl

	Recipe		Inventory, bbl			Price
Component	Vol%	bbl	Initial	Final	Remaining	$/bbl
n-Butane	4.56	4,200	0	100,000	95,800	50.51
Natural gasoline	28.2	0	0	0	0	76.38
Light naphtha	13.02	26,000	0	100,000	74,000	75.12
Medium naphtha	0	12,000	0	100,000	88,000	75.78
Heavy naphtha	0	0	0	100,000	100,000	76.44
Alky	0	0	0	0	0	96.75
Heavy reformate	0	0	0	0	0	113.05
Isom	0	0	0	0	0	80.74
MTBE	0	0	0	0	0	97
ETBE	0	0	0	0	0	107
CG87 reg	54.23	50,000	0	100,000	50,000	87.03
CG93	0	0	0	0	0	92.15

TABLE 3. Downgrade GC87 to CBOB A4 by using bio-ETBE, with a profit of $0.77/bbl

	Recipe		Inventory, bbl			Price
Component	Vol%	bbl	Initial	Final	Remaining	$/bbl
n-Butane	6.45	6,452	0	100,000	93,547.80	50.51
Natural gasoline	0	0	0	100,000	100,000	76.38
Light naphtha	0	0.01	0	100,000	99,999.99	75.12
Medium naphtha	33.43	33,425.78	0	100,000	66,574.22	75.78
Heavy naphtha	0	0	0	100,000	100,000	76.44
Alky	0	0	0	100,000	100,000	96.75
Heavy reformate	0	0	0	100,000	100,000	113.05
Isom	0	0	0	100,000	100,000	80.74
MTBE	0	0	0	0	0	97
ETBE	13.09	13,090.03	0	100,000	86,909.97	107
CG87 reg	47.03	47,031.99	0	100,000	52,968.01	87.03
CG93	0	0	0	0	0	92.15

check valves to prevent the "flashing" of butane pushing back against the gasoline in the fill line. An inline static mixer (approximately $7,000–$8,000) is also required to ensure blend homogeneity to cut down on circulating the tank [to be determined by testing the degree of homogeneity achieved with and without circulation (4 hr, 8 hr, 16 hr), and then interpolating/extrapolating as needed].

This scheme will produce a pressure drop of approximately 10%, so sufficient pumping capacity must be provided. The quantity of butane injected is measured with a butane flowmeter (turbine or Coriolis- type, at a cost of $5,000–$12,000, depending on type).

A variation of this scheme is to inject butane sequentially using the same scheme, where the amount of butane injected is measured with a butane tank gauge (on the bullet). This saves the cost of a butane flowmeter but prolongs the blending time, and it can require additional homogenization time via circulation.

Injection of butane and/or naphtha directly into the product tank. In this scheme, butane is sequentially injected into the tank filling line after the gasoline product has been pumped into the tank. This means that a tank sample can be taken and its properties analyzed, allowing the determination of the maximum amount of butane that can be injected without throwing the gasoline product off spec. A disadvantage is that it takes much longer to homogenize the tank sample and analyze the tank, calculate the amount of butane to be injected, physically add the butane, circulate the tank to ensure homogeneity, sample the tank again, and ensure it is on spec. This can easily add approximately 24 hr to the cycle from beginning to end to "final" the product tank.

The scheme (shown in FIG. 2) determines the amount of injected butane as measured with a butane tank gauge (on the bullet); if not, a butane flowmeter will be required at additional cost.

Although this scheme uses a high-efficiency vortex nozzle mixer, it is not as time-efficient as the first scheme mentioned here with the sparger and static mixer; therefore, additional circulation time must be allocated before taking tank samples. The time can be determined experimentally.

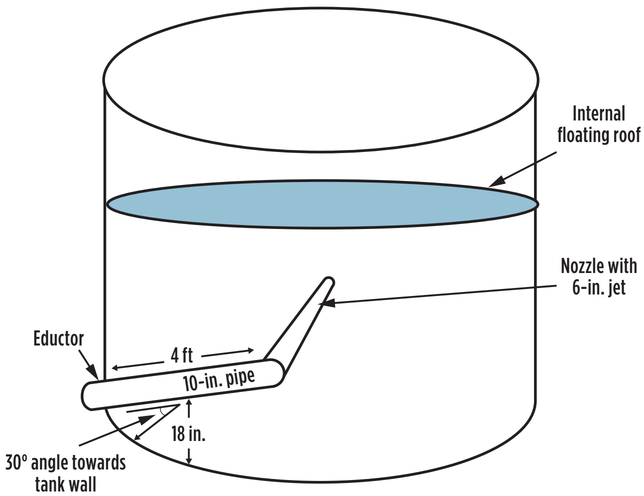

FIG. 2. Sequential butane blending.

Inline blending of butane and/or naphtha into the product tank. This scheme allows for precision blending of the maximum possible amounts of butane and naphtha to maximize gross profit per barrel. The price for this is the additional cost of a skid-mounted inline blender, an online RVP analyzer and blending software. A typical design is shown in FIG. 3.

The typical cost of the inline blender with three streams [P/L gasoline, butane and natural gas liquids (NGL)] ranges from $300,000–$700,000 (~$150,000 per meter run, plus $150,000 for an analyzer, plus blending software). Typical performance is within the ASTM precision of measurement (r = 0.2 ON, RVP

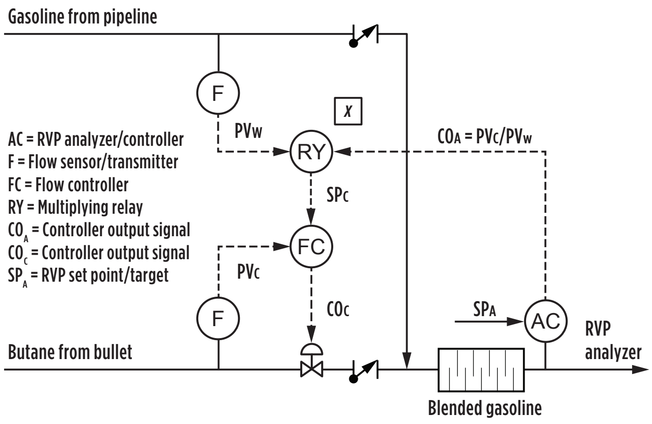

FIG. 3. Inline blending of butane.

TABLE 4. Calculation of butane properties from GC compositional analysis

Sphere 235	GC	From ASTM DS 4B			Calculation per ASTM D2598		
Component	**Vol%**	**RVP**	**RON**	**MON**	**RVP-bbl**	**RON-bbl**	**MON-bbl**
Propane	0.998	188	101.8	97.1	187.624	101.5964	96.9058
I-Butane	8.882	72.6	100.1	97.6	644.8332	899.0882	866.8832
n-Butane	78.345	51.7	93.8	89.6	4,050.44	7,348.76	7,019.71
I-Butene	0.269	63.3	97.4	80.8	17.0277	26.2006	21.7352
I-Pentane	7.066	20.4	92.3	90.3	144.1464	652.1918	638.0598
n-Pentane	2.8	15.6	61.7	62.6	43.68	172.76	175.28
					RVP	RON	MON
Results	**98.36**				**51.73**	**93.44**	**89.66**

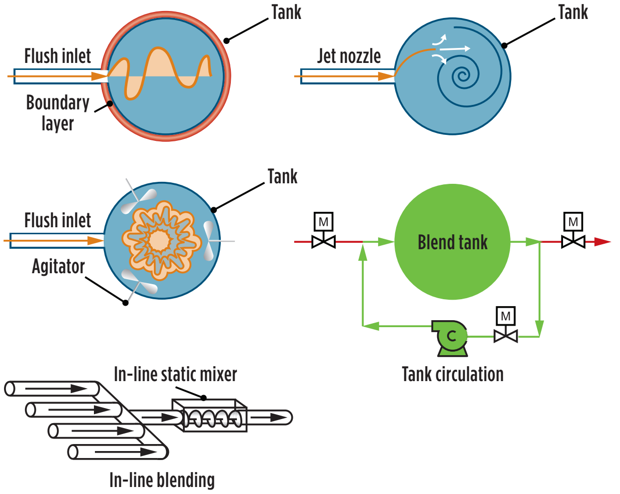

FIG. 4. Tank mixing techniques.

r = 0.16 psi). Because it is prefabricated, it can be installed, started up and commissioned within 2 wk–3 wk after delivery.

OTHER CONSIDERATIONS

Accuracy of gasoline, butane and naphtha properties. The measurement of gasoline and naphtha properties can be done directly by any competent third-party lab. The measurement of butane properties is based on ASTM D2598 gas chromatographic analysis of components, so it is vital to get a representative sample of the blending butane and calculate the properties (see **TABLE 4**). Using chemical handbook properties is not recommended.

Property analyzers. It is highly recommended to acquire table-top RVP and (possibly) multi-property analyzers that also measure research octane number (RON), motor octane number (MON), RVP, specific gravity (SG), etc., and allow quick analysis of samples in minutes, whether tank samples or pipeline samples.

It is equally important to take samples per ASTM D5842 practice to ensure sample integrity. Samples should be taken in ASTM recommended sample bottles and stored in a cold room/refrigerator until ready to use.

Tank homogenization. Many techniques exist for homogenizing the contents of a tank to meet U. S. Environmental Protection Agency (EPA) homogeneity requirements of a maximum 6° API difference between the top third, middle and lower third of the liquid level in a tank (**FIG. 4**). This requires a 95% homogeneity.

Jet nozzle mixing is quite effective, depending on the type of nozzle—the recommended nozzle is an "eductor-type" jet nozzle. An inline blender with a static mixer is highly effective; however, a cheap inline static mixer requires a relatively expensive inline blender.

The use of electric motor-driven "propeller-type" mixers or agitators is quite effective, but this takes a long time compared with the other methods. If not already installed, this is not recommended.

Tank circulation works well but requires additional expenses in the form of two different tank lines (i.e., fill lines, suction line), a pump and manifolding with isolation valves. Achieving 95% homogeneity requires approximately one tank turnover—for example, a 20,000-bbl tank with a 1,000-bph pump capacity will take approximately 20 hr (20,000 bbl/1,000 bph = 20 hr).

Project management. It is easy to fall into a trap of do-it-yourself being less expensive than having a single point of responsibility. Conversely, the extra 10%–15% cost is worth it to ensure the work is accomplished on time and within budget.

The single most crucial factor is the selection of experienced vendors/contractors that are willing to provide performance guarantees against a 10%–15% contract value retention until performance is demonstrated via a site acceptance test (typically a 2-wk duration). HP

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Uncommon lessons: Shell-and-tube heat exchangers—Part 1

Shell-and-tube heat exchangers (STHEs) are the most common heat transfer process equipment in all types of industrial plants. Due to the variety of available construction options, an STHE can be suitably designed for most processes and design conditions and can be constructed from different materials or combination of materials. STHEs are typically manufactured in accordance with international or national codes or standards, with the American Society of Mechanical Engineers (ASME) Code[1] being the most popular, along with associated Tubular Exchangers Manufacturers Association (TEMA)[2] and American Petroleum Institute (API) Standard 660[3] requirements.

According to the ASME Code, an STHE is a multi-chamber vessel, with two chambers for most constructions that are commonly addressed as shell-side and tube-side or channel-side. In an STHE, the tubesheet, tubes, floating head (if applicable) and internal expansion bellow (if applicable) are the common elements. Depending upon process needs, the STHE may have a variety of external and internal components, such as cylinders, concentric and/or eccentric cones, dished heads, thick or thin expansion bellows, tubes (straight, u-tube, low fin, twisted, etc.), girth flanges, tubesheets, bolted covers, nozzles, multi-purpose nozzles, baffles, tie-rods, impingement rods, sealing strips, sliding strips, bundle pulling eye bolts, saddle support, lug support and skirt support (for large and long exchangers). **FIG. 1** illustrates a floating head type heat exchanger and its major parts/components.

Apart from designing components to comply with applicable pressure and coincident temperature conditions and evaluating thicknesses or stresses in different components, there are specific requirements in the ASME Code, TEMA Standard and the API Standard 660 that are often not complied with in design and early fabrication stages. Based on the authors' opinion, failure to identify these during design reviews leads to costs that must be corrected at later stages in fabrication.

This article focuses on specific types of lessons and design limitations that none of the commercial design programs (software, Excel spreadsheets, etc.) will identify with their "help" menus or warnings. Merely checking drawings with respect to design calculations is insufficient to ensure thorough compliance and reliable product design that will operate (thermally and mechanically) as intended.

The authors' purpose is to shed light on those uncommon but valuable lessons that are not discussed in reference manuals or design guides. These lessons will be helpful in engineering and design activities.

Maximum allowable working pressure (MAWP). The authors encountered shell-side MAWP calculation for an exchanger with a thick (flanged and flued) expansion bellow. This expansion bellow was designed (separately) using finite element analysis (FEA) with shell-side design pressure; therefore, the MAWP for the expansion bellow is the shell-side design pressure. Surprisingly, a higher shell-side MAWP obtained from a design report generated via a computer program was indicated on the drawings and accordingly was carried over in the ASME forms and equipment nameplate. The higher MAWP was based on the design of other parts of the shell-side chamber, excluding the expansion bellow.

Note: When a part of a pressure chamber (in this example, the bellow) is designed using an FEA program, the pressure used to design the part becomes the MAWP of that part, unless a higher MAWP is used in the FEA. This should not be missed when evaluating the govern-

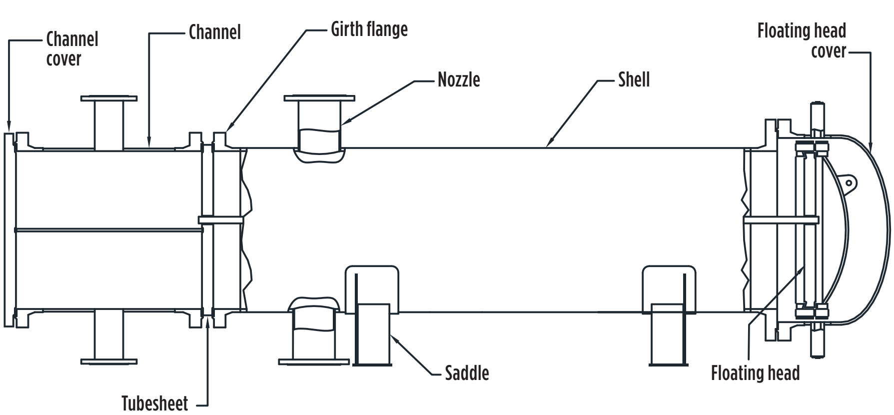

FIG. 1. Floating head heat exchanger.

ing MAWP of the chamber. The MAWP of the chamber is the lowest MAWP of all the parts that make up the chamber. Due to the complexity of expansion bellow calculations, the computer program may not be able to model the equipment inclusive of the expansion bellow to determine the shell-side MAWP. When any part of an exchanger is designed using an FEA, the pressure used in the FEA should be considered for MAWP calculation; otherwise, a higher pressure may get stamped on the nameplate and ASME forms.

A similar situation may arise for tube-side, single-pass, TEMA-type AES exchangers that are provided with tube-side internal expansion bellows. The bellows are designed considering shell-side and tube-side design conditions separately—it is possible that the internal bellows are not verified to shell-side and tube-side MAWPs.

Design of common elements. Regarding design pressure for common elements, such as tubes, tubesheet and floating head assembly, when a full vacuum exists on the shell-side or tube-side (or both sides), vacuum pressure on one side should be added to the design pressure of the opposite side to arrive at the final design pressure for the applicable side, according to UG-21 of the ASME Code.[1]

The authors have encountered many heat exchangers in which the floating head cover and flange, and tubes were designed without considering the full vacuum on the shell side.

Coefficient of thermal expansion (TE). The coefficient of thermal expansion (TE) is required to verify the shell-side differential thermal expansion stresses. The TE values in Tables TE-1 to TE-5 of ASME Section II-D[4] provide the values of TE coefficients for temperatures down to 20°C (68°F).

When evaluating the need for the expansion bellow for heat exchangers in low-temperature and cryogenic service, the TE at the mean metal temperature (MMT) of the materials should be used. It is obvious that at lower temperatures, materials will experience contraction rather than expansion. A common understanding among code users is to apply the proper value of TE from ASME Section II-D (Material Properties) to perform mechanical design. However, TE at MMT below 20°C (68°F) is not contained in ASME Section II-D because the Materials Code only provides TE down to 20°C (68°F), while for this type of design condition it is necessary to use a TE value of far below 20°C (68°F).

If the TE at a sub-zero MMT is unavailable, other references should be explored to source TE at a sub-zero MMT to use in the analysis rather than using the TE at 20°C (68°F). This critical information is available in ASME B 31.3 (Piping Code)[5] or any other reference book. This was clarified by ASME Code[1] in the following interpretation number 14-1240.

> Standard designation:
> BPV Section VIII Div. 1
> Edition 2010/Addenda 2011
> Paragraph/Figure/Table No.:
> UHX-13
> Subject description:
> Axial differential thermal expansion between tubes and shell
> Date issued: 04/08/2015
> Record Number: 14-1240
>
> Question (1): Are the rules in Part UHX valid if the MMT of the shell or tubes, or both, are below 20°C (68°F)?
>
> Reply (1): Yes
>
> Question (2): In accordance with paragraph U-2(g) and the Introduction to Subpart 2 Physical Properties Tables in Section II, Part D, may other sources be used for values of TE when the material or temperature is not listed in Tables TE of Section II, Part D?
>
> Reply (2): Yes.

In one project that contained fixed tubesheet exchangers in cold service, it was observed that the design calculation report mentioned a TE value at 20°C (68°F), even if the value of MMT was in negative single or double digits because the computer program referred to ASME Section II, Part D database in which the lowest temperature for TE is 20°C (68°F), and the same was used for developing the expansion bellow design. This led to a bellow design with an incorrect number of bellow convolutions.

Length of tube expansion for UHX calculations. ASME and TEMA codes[1,2] specify the tube expansion details with or without grooves; however, light expansion is not mentioned in either of these codes. API Standard 660[3] mentions light expansion as one where tube wall thinning is < 2%. In many instances, the exchanger data sheet specifies strength welded tubes to be lightly expanded for a tube-to-tubesheet joint (TTSJ).

The purpose of light expansion is to establish metal-to-metal contact between

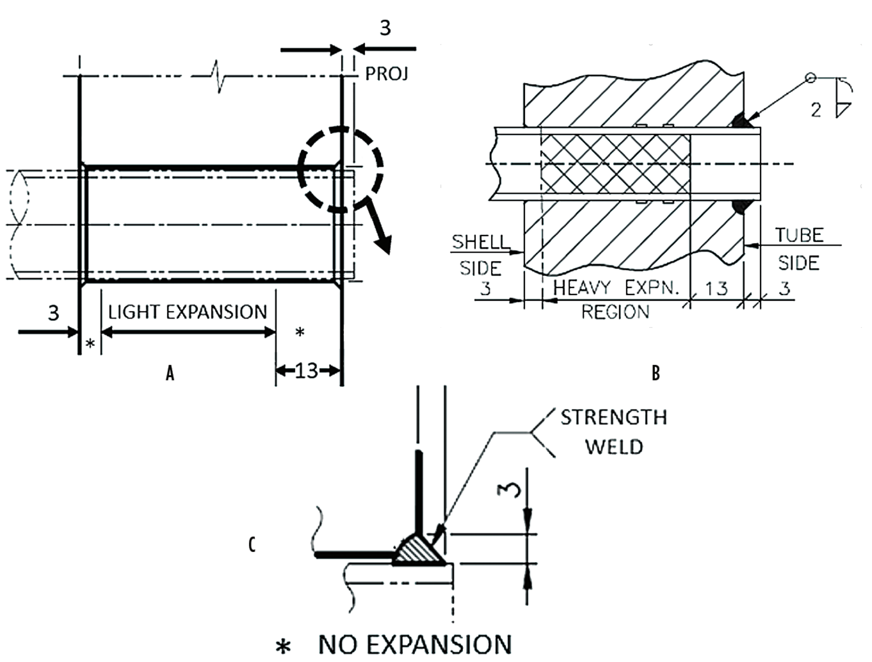

FIG. 2. Tube-to-tubesheet joint details: welded with light expansion (A) and expanded with two grooves (B).

tube and tubesheet. Light expansion of tubes in tube holes does not, in any capacity, provide mechanical strength to overall TTSJ capacity except by centering the tubes in the tube holes and helping to reduce crevices (large gaps) between the tube hole and the tube outside diameter (OD). Mock-up tests for such a TTSJ do not include expansion related parameters (torque, tube wall thinning, etc.), and the joint is purely qualified considering the weld for load carrying capacity.

ASME Code Part UHX calculations for tubesheets require the length of tube expansion in the calculations to be considered in those equations. The description of ℓtx in nomenclature of UHX-5.1 emphasises various factors to be considered for expansion length, which is clearly shown in this excerpt from ASME Code:[1]

> ℓtx = expanded length of tube in tubesheet ($0 \leq \ell tx \leq h$) [see Figure UHX-11.3-1, sketch (b)]. An expanded tube-to-tubesheet joint is produced by applying pressure inside the tube such that contact is established between the tube and tubesheet. In selecting an appropriate value of expanded length, the designer shall consider the degree of initial expansion, differences in thermal expansion, or other factors that could result in loosening of the tubes within the tubesheet.

If the length of light expansion is considered in the strength calculation of the tubesheet, the tubesheet calculation will provide significantly reduced required thickness, as the equations are written so that the expansion length will add to the strength of the tubesheet; however, the equations do not differentiate between light and heavy expansion and only heavy expansion will aid in strengthening the TTSJ.

The industry uses different terminology for expansion, one being light expansion, or light-rolled and expanded with or without groves. Light expansion is considered when tube thinning is 1%–3%; mechanically, this aids the tube OD to contact the tubesheet hole inside diameter (ID).

Conversely, tube expansion carried out for strength purpose has a minimum wall thinning of 5%—depending on the material of the tube and tubesheet. Often, such expansion is provided with grooves in the tubesheet where tube material will flow during the expansion process. It is the engineer's choice to take advantage of tube expansion in the tube hole. As discussed earlier, light expansion does not contribute to the TTSJ capacity. If the TTSJ is lightly expanded tubes, the expansion length of the tubes should not be considered in the calculations (as its effect towards strengthening the tubesheet will be nearly "zero"). **FIG. 2** shows different types of commonly used tube-to-tubesheet joints in the industry.

The authors noted tubesheet calculations that were using the lightly expanded length of tubes in the equations and arriving at thinner tubesheets to save material thickness and cost, jeopardizing the strength and long-term reliability of the TTSJ. In those examples, the tubesheets were calculated 20 mm thinner than the actual required thickness computed without considering the lightly expanded length of tubes in the calculations.

Incorrect flange finish. Kammprofile, camprofile or "grooved" gaskets are made of a grooved, solid metal core with soft coating of suitable non-metallic sealing layer(s) [graphite, polytetrafluoroethylene (PTFE), etc.] on each side. According to API Standard 660, the gasket contact surface required for a kammprofile gasket is 125 micro-in.–250 micro-in. However, the authors noted that for some heat exchangers, a 63 micro-in. surface roughness finish was used for gasket faces. A flange gasket surface roughness of 63 micro-in. is appropriate for solid metal gaskets, while a kammprofile gasket uses solid metal (core) but has a soft covering on the top and bottom faces; therefore, a higher surface roughness is recommended. This type of inaccuracy will lead to a non-performing body flange and is likely to jeopardize the exchanger.

> While the tube-to-tubesheet joint, girth flange and expansion bellow are the most critical components in an STHE, often the least attention is paid to these parts in the design and review process. These components must be specified, designed and reviewed thoroughly to avoid loss of integrity.

Incorrect gasket factor "m" and seating stress "Y" for a kammprofile gasket. The value of "m" and "Y" for a kammprofile gasket varies from manufacturer to manufacturer. To perform the mechanical design of a girth flange using a kammprofile gasket, the correct gasket factor "m" and seating stress "Y" values must be obtained from the manufacturer to ensure the production gasket specifications match the values used in the design of the girth flange for production. In one case, the mechanical design of a girth flange with a kammprofile gasket was performed using "m" and "Y" values from internet sources; when the actual gasket manufacturer's certificate was received, the "m" and "Y" values were larger compared to those used in the design and construction of the girth flange. The larger "m" and "Y" values per the gasket manufacturer's certificate overstressed the flange, causing the already-manufactured girth flange to fail ASME Code requirements.

Shell-side vent and drain nozzle for vertical fixed tubesheet heat exchanger. All chambers of shell-and-tube heat exchangers should be capable of being vented and drained independent of process piping. A fixed tubesheet heat exchanger is often provided with vent and drain connections. For a horizontal exchanger, there are many location choices for the vent and drain nozzles; however, for a vertical fixed tubesheet exchanger—if provided on the shell—there is always some dead space left out without complete venting and draining. The preferred method is to provide vent and drain on the tubesheet rather than on the shell: this allows complete venting and draining of shell-side fluid. Tubesheets are drilled

vertically through half of the thickness and then further drilled horizontally to vent or drain out to the atmosphere, as shown in **FIG. 3;** and a similar arrangement can be applied to drain nozzle.

Lack of baffle support (to the tubebundle) due to a flanged and flued expansion joint. A flanged and flued expansion joint is typically provided with an internal sleeve to assist the shell-side flow; however, a sleeve may not be necessary in a vertical exchanger. An internal sleeve is necessary for process reasons to minimize the frictional losses or pressure drop and ensure smooth shell-side flow.

For horizontal exchangers with a flanged and flued joint, an internal sleeve is purposely required for mechanical reasons and to support the baffle (as well as prevent the tube bundle from sagging) because a possibility exists that one or two baffles will most likely be located along the length of the expansion joint where a portion of cylindrical shell will be unavailable due to placement of the expansion joint. Without a sleeve or liner, a baffle (or baffles) that falls within the ends of the flanged and flued joint will lack shell support. The sleeve acts as the shell and provides mechanical support to the tube bundle to resist gravity.

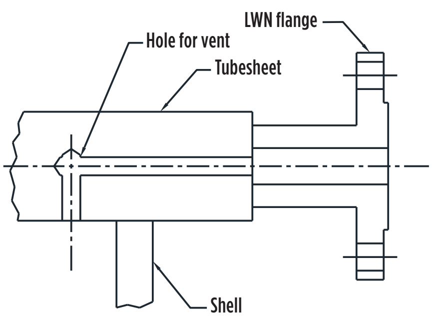

FIG. 3. Vent and/or drain nozzle arrangement for vertical heat exchanger.

Without the sleeve, maldistribution of shell-side flow, resonant vibrations or sagging of the tube bundle—or all these combined—can ultimately cause the exchanger to fail. The authors encountered some horizontal exchangers with flanged and flued expansion joints in which internal sleeves were not provided.

Consider **FIG. 4C:** a sleeve is still required where baffles are clearing the expansion joint, which is not designed to share part of the bundle weight (acting as a point load). For the situation shown in **FIG. 4B,** a sleeve is necessary to provide baffle support. Providing a sleeve will also give more flexibility with respect to baffle location. **FIG. 4A** illustrates an acceptable construction.

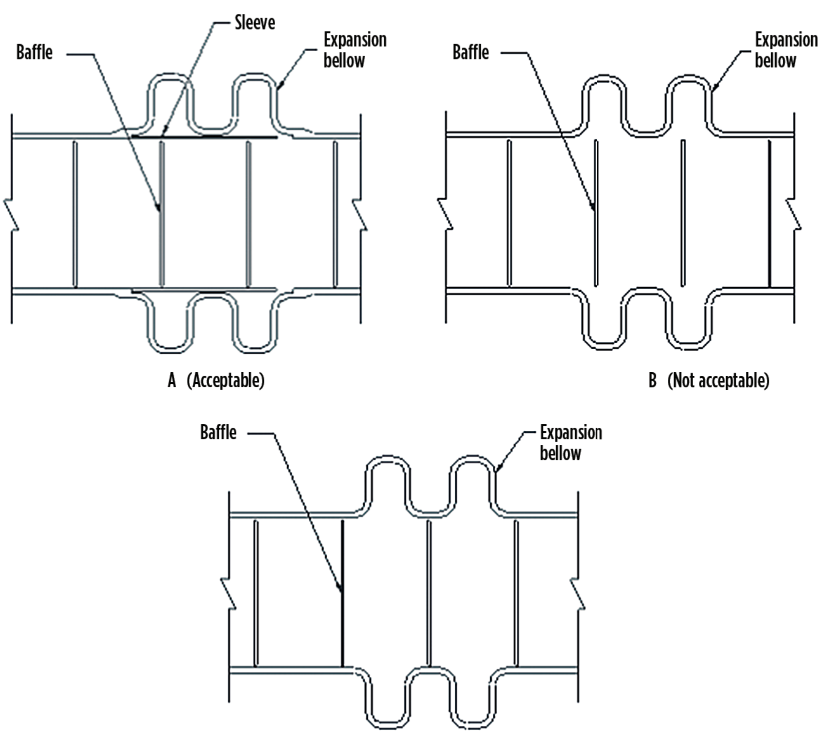

FIG. 4. Acceptable construction of expansion bellow (A) and unacceptable construction (B and C).

Design review experience is acquired by continuous practice and improvement, and the authors believe that the feedback of uncommon lessons is helpful.

Part 2 of this article will appear in the May issue. HP

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[1] American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section VIII, "Rules for construction of pressure vessels—Division 1," New York, New York, July 2019.
[2] "Standards of the Tubular Exchangers Manufacturer's Association Inc. (TEMA), 10th Ed., 2019.
[3] American Petroleum Institute (API) Standard 660, "Shell-and-tube heat exchangers," 9th Ed., Washington, D.C., May 2020.

Complete literature cited available online at www.HydrocarbonProcessing.com.

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Air-cooled heat exchanger operation under emergency cooling service

One of the challenges in the operation of air cooled heat exchangers (ACHEs) is to decide whether or not to operate under natural convection. There is limited information available for the simulation of an ACHE with no fans under operation. Under emergency conditions, such as fan failures or when bringing the ACHEs onstream from standby conditions to meet emergency cooling requirements, with none of the fans operating, the use of natural convection becomes unavoidable. This article discusses case studies to evaluate the pros and cons of both options:

1. Operating with fans running on emergency power
2. Operating in natural convection with none of the fans operating to meet the emergency duty conditions.

ACHE under natural convection. Simulation of ACHE performance under natural convection has the following limitations:

- **Non-availability of sufficient experimental data:** Most of the available experimental data based on wind tunnel tests are applicable for the large natural draft cooling towers with high natural draft velocity and are not applicable for ACHEs in process industries with relatively smaller sizes and lower natural draft velocity.
- **Impact of structures, heat source, local wind velocity and ground effect:** All these factors affect the natural draft by impacting the velocity of air at the exit of the ACHE. None of the available thermal design software considers these parameters in sizing an ACHE. Therefore, a detailed computation fluid dynamic (CFD) analysis, with its associated impact on project cost and time, is required to properly simulate the impact of natural convection.
- **Effect of chimney (stack) on the performance:** It has been established that the use of a chimney (stack) on top of the air cooler bundle (for forced draft unit) and on top of the fan ring (for induced draft unit) enhances the effectiveness of heat transfer due to natural convection. However, it is still a work in progress as far as the exact relationship of chimney height with natural draft performance is concerned.

Initial proposition: Avoid natural convection and use emergency power. In view of the challenges highlighted in simulating ACHE performance under natural convection, three services were proposed to operate the ACHEs during emergency conditions with the fans running on emergency power (**TABLE 1**). This operation allows achieving higher airside velocity, resulting in a higher mean temperature difference and higher airside heat transfer coefficient. As a result, the capital cost is reduced by decreasing the number of bays and/or heat transfer surface area vs. the natural draft option.

How dependable is emergency power? For emergency cooling scenarios, the likelihood of fan motor failure at startup was reviewed for the following four conditions:

1. Will the emergency cooling scenario with all fans off be the governing case?
2. If the above is true, can emergency cooling be met with the help of emergency power, which is being provided as backup power for the process unit, to power the fan motors during startup?
3. Will there be a case of double jeopardy when the motors may fail to start even with emergency power?
4. If double jeopardy is a possibility, can the air cooler

TABLE 1. Three service cases for ACHE usage during emergency conditions

Service #	Case of operation	Fans in operation	Cooling mechanism	Remarks
1	Normal operation	All	Forced draft	Controlling case: Fans on normal power
1	Emergency cooling	1 out of 4	Forced draft	Alternate case: Fan on emergency power
1	Emergency blowdown	1 out of 4	Forced draft	Alternate case: Fan on emergency power
2	Normal operation	All	Forced draft	Controlling case: Fans on normal power
2	Emergency cooling	2 out of 3	Forced draft	Alternate case: Fan on emergency power
3	Normal operation	All	Forced draft	Controlling case: Fans on normal power
3	Emergency cooling	1 out of 6	Forced draft	Alternate case: Fan on emergency power

meet the specified duty by operating under natural convection?

A closer review of the four conditions and the experience of similar applications revealed that double jeopardy is indeed a possibility. This will not only make the use of emergency power for operating the ACHEs under emergency cooling scenarios unacceptable, but will also result in the emergency cooling case—under natural draft instead of forced draft with 1 of the 4 fans operating—becoming the controlling case. Instead of normal operation, the emergency cooling case will govern the overall size of the ACHE.

FIG. 1. Induced-draft ACHE with chimney. Photo courtesy of Spiro-Gills.

Final options—Natural draft with or without chimney.

To size the ACHE for the controlling case (i.e., emergency cooling scenario) and to arrive at a final configuration of the ACHE, the following two possible options were reviewed. The simulation was carried out using standard commercial heat transfer software[a].

Option 1—Natural convection without a chimney: Increase the heat transfer area to take care of the loss in overall heat transfer effectiveness—due to natural convection—by increasing the number of bundles/bays and the number of bays over and above those required for normal operation case. In addition, increase the number of tube rows—over and above those required for the normal operation case—to increase the stack effect and facilitate natural draft.

Option 2—Natural convection with a chimney: Increase the velocity of natural convection over the ACHE bundles by providing a chimney (stack) on top of the bundle without increasing the number of bundles and bays from those required to cater to the normal operation cases.

The results of the two options, along with the initial option, are summarized in **TABLE 2.** Since Option 2 requires less plot space and lower surface area for all three services, it was preferred over Option 1.

Type of draft: Forced or induced.

The chimney can be located either on the top of the tube bundles when fans (which are required for normal operation) are below the bundle (forced draft), or on top of the fan ring when fans are above the bundle (induced draft) (**FIG. 1**).

TABLE 2. Evaluation of various options

Service No.	Option	Controlling case	Type of draft	Bare area, m^2	No. of bays	No. of bundles per bay	No. of tube rows	Tube length, mm	No. of fans per bay/ total fans	Plot area, m x m	Chimney height, mm
1	Initial	Normal Operation[1]	Forced	591	2	2	5	11,000	2/4[1]	11 × 10	Not applicable
1	1	Emergency cooling[2]	Natural	4,968	9	2	8	11,000	–	54 × 10	No chimney
1	2	Normal operation[2]	Natural	555	2	2	4	11,000	–	12 × 10	4,000
2	Initial	Normal operation[3]	Forced	176	1	1	4	11,000	3/3[3]	3.6 × 11	Not applicable
2	1	Emergency cooling	Natural	5,433	10	1	12	11,000	–	39 × 11	No chimney
2	2	Emergency cooling	Natural	184	1	2	2	11,000	–	7.8 × 11	7,000
3	Initial	Normal operation[4]	Forced	851	3	2	6	11,000	2/6[4]	12.5 × 11	Not applicable
3	1	Emergency cooling[5]	Natural	2,726	6	2	9	11,000	–	27 × 11	No chimney
3	2	Normal operation[5]	Natural	912	3	2	6	11,000	–	14 × 11	3,000

[1] For the emergency cooling case, only 1 of 4 fans will be in operation, and the fan motor will be on emergency power.
[2] Emergency cooling, with all fans off and without a chimney, is the controlling case. However, with all fans off and with a 4,000-mm chimney, normal operation is the controlling case.
[3] For the emergency cooling case, only 2 of 3 fans will be in operation, and the fan motor will be on emergency power.
[4] For the emergency cooling case, only 1 of 6 fans will be in operation, and the fan motor will be on emergency power.
[5] Emergency cooling, with all fans off and without a chimney, is the controlling case. However, with a 3,000-mm chimney, normal operation is the controlling one.

The induced draft option, with a chimney on top of the fan rings, has the following advantages over the forced draft option:

- **A lower chimney height:** The induced draft design provides sufficient draft to allow the advantage of using a lower height chimney.
- **A lower impact of prevailing wind on ACHE performance:** In the induced draft configuration, the cross-sectional area of the fan ring is lower vs. the bundle face area (which is almost 2.5 times the fan area) in case of a forced draft ACHE. As such, a relatively higher exit velocity results in a low impact of prevailing wind on ACHE performance.
- **Better protection of the tube bundles:** The induced draft design protects the tube bundles from heavy rain and weather elements, with the plenum chamber on top of the tube bundle. Therefore, a removable protective roof for tube bundles is not required with an induced draft design.

Based on the overall advantage of operation, it was recommended to select Option 2 with induced draft configuration for all the three services.

Takeaway. Natural convection, in combination with forced or induced draft, is preferred over emergency power configuration for applications where an ACHE must be put into operation quickly from standby mode due to process consideration. The following points must be reviewed in detail before finalizing an ACHE configuration:

- Consider the limited availability of performance data of an ACHE under natural convection in process industry applications. The various pros and cons of the natural draft option with respect to other forms of operation (e.g., operating the ACHE fan motors under emergency power mode) must be reviewed during the project definition phase before finalizing the optimum mode of operation.
- The type of draft, whether forced or induced, to be adopted in combination with the natural convection mode should be decided based on the site condition (e.g., prevailing wind direction, presence of heat sources in the vicinity and annual rainfall) and specific customer requirements.
- The limitations of available software for ACHE performance simulation must be considered before deciding whether a detailed CFD analysis will be required to simulate the performance of the ACHE under natural draft conditions. HP

NOTE

[a] Heat Transfer Research Institute's X_{ace} software

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Preferential baffle reboiler—Part 1

Distillation towers consume ~30% of the energy in a refinery or petrochemical facility. The reboiler is the stomach of the distillation tower that consumes the energy to separate the components. Any improvement in design or operational flexibility will save the energy and profitability of the plant. Two main types of reboilers are in use: a circulating (conventional) reboiler and a once-through reboiler.

A preferential baffle reboiler is simply a combination of a once-through and circulating reboiler, and is more efficient than the circulating reboiler and more flexible than a once-through reboiler. This thermosyphon, or forced reboiler, can take liquid directly from the tray as well as the product. It is also called a baffle with an underflow or a baffle with a large hole.

This article will describe the principle of the preferential baffle reboiler and its working mechanism, as well as the hole sizing in the baffle and some design guidelines. The reasons the preferential baffle is required and what the fluid flow direction should be through the hole of the baffle are discussed.

Two types of reboiler are available based on the driving force: forced and thermosyphon.

Circulating reboiler.

For a circulating reboiler, the name itself suggests that liquid circulates through the reboiler continuously. The liquid outlet of the reboiler always recirculates through the reboiler. The tower bottom product and reboiler inlet are the same and all properties are identical. The bottom sump of the column is always filled with liquid, so the circulating reboiler is not limited by liquid and there is little chance of dry out. However, this depends on the level of the sump of the column due to the head of the level for thermosyphons.

The reboiler outlet temperature is always higher than the tower-bottom temperature.[1] The drawback of the circulating reboiler is its separation efficiency. Due to remixing of the reboiler outlet liquid with the bottom tray liquid, the liquid inlet temperature is always higher, which reduces the logarithmic mean temperature difference (LMTD) across the reboiler and reduces the separation in the reboiler. This is why a circulating reboiler is not considered as a theoretical separation stage. Lighter components can pass downstream at the bottom with liquids.

FIG. 1A shows the circulating reboiler configuration without a baffle, with a variable head based on level. This is applicable when product withdraws and is less often compared to reflux ratio or reboiler circulation.[2] FIG. 1B shows the circulating reboiler with a baffle at the bottom of the column. This is a constant head reboiler and does not depend on the level of the product in the compartment. Liquid always flows over the baffle. It is applicable when the withdrawal of product is 70%–80% of the circulation rate or higher than the reflux rate.

Once-through reboiler.

Matching its name, the reboiler circulates liquid through the reboiler only once. The liquid inlet to the reboiler is drawn directly from the bottom tray of the column, and the reboiler return liquid is the product of the column. The product of the column and the reboiler inlet liquid are different from each other and at different temperatures. The temperature of the reboiler inlet liquid is colder than the product temperature, so the log-mean temperature of the reboiler is higher. This is a theoretical stage of the column.

Liquid from the bottom tray should not bypass the reboiler, a main part of the column. As per Lieberman,[1] "A once-through

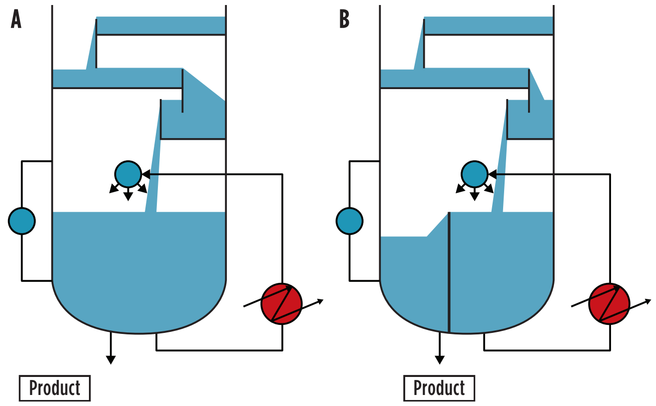

FIG. 1. A circulating reboiler without baffle (A), and a circulating reboiler with baffle (B).

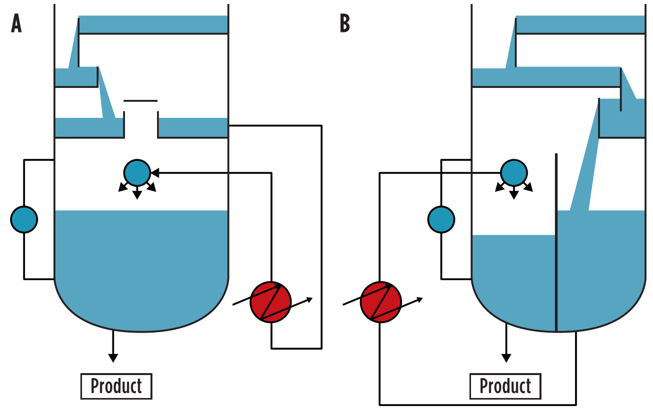

FIG. 2. A once-through thermosyphon reboiler without baffle (A), and a once-through thermosyphon reboiler with baffle (B).

thermosyphon reboiler not only functions as the bottom theoretical stage of a tower, it also functions as if it is a superfractionation stage. This means that it is more important than any individual tray in the tower. This is especially true with a multi-component tower bottoms product."

While this type of reboiler is often considered the most effective out of all types of reboilers due to its superior thermal efficiency, it also has many drawbacks. If the bottom tray is leaking, then the liquid will bypass the reboiler and reduce efficiency. Reboiler draw-off plugging or seal pan damage may also restrict the liquid to the reboiler and overflow to a bottom sump. Many failures can occur, such as a hole in the bottom tray or in the collation box, a broken bottom tray, or weeping through the bottom tray.[3]

FIG. 2A shows the once-through reboiler without baffle. The reboiler takes liquid from the bottom tray and returns it to the bottom sump. **FIG. 2B** shows the once-through reboiler with baffle. All the liquid from the bottom tray is diverted towards the reboiler compartment; the reboiler takes liquid from this compartment and returns it to another compartment, also called the product compartment.

The once-through with baffle reboiler has two major problems: hydraulic balance and a startup issue.

When the liquid circulation rate through the reboiler is higher than (double or more) the product withdrawal rate, the reboiler takes the liquid from the reboiler compartment (which comes directly from the bottom tray) and the return (effluent) of the reboiler sends the liquid and vapor mixture into the product compartment, where the vapor and liquid separate from each other and disengage. Disengaged vapor flows upward, and liquid dumps into the product compartment and is withdrawn as a product. If this disengaged liquid rate in the product compartment is higher than the product withdrawn, then liquid accumulation will start and the level of the product compartment will increase continuously. The liquid will fill up until baffle overflow or level control of the bottom product increases, which disturbs the downstream process. If the reboiler-return nozzle elevation is lower than the height of the baffle, then the return nozzle will dip into the liquid, which may reduce the density of the liquid and the level transmitter would show a lower liquid level than the actual level.

Another problem with a higher liquid level is that the return-nozzle submerges, dipping into the liquid and resulting in slug flow or creating a pressure surge that can dislodge the tray of packing in the tower.[4] Reboiler return liquid may impinge on liquid, which also causes level fluctuation. An example of material balance issue (hydraulics) is shown in **FIG. 3.** The reboiler circulation rate is 300 tph and the thermosyphon reboiler produces 30% vapor and 70% liquid as a return. That equals 210 tph as a liquid product and 90 tph as vapor.

All the vapor produced by the reboiler will move up towards the trays, and 210 tph of liquid will dump into the product sump compartment. The product withdrawal rate is 190 tph, which means 20 tph accumulates every hour. The level of the product compartment increases, which increases the bottom flowrate if the level controller is in auto mode; otherwise, the product sump fills up until it overflows into the reboiler compartment.

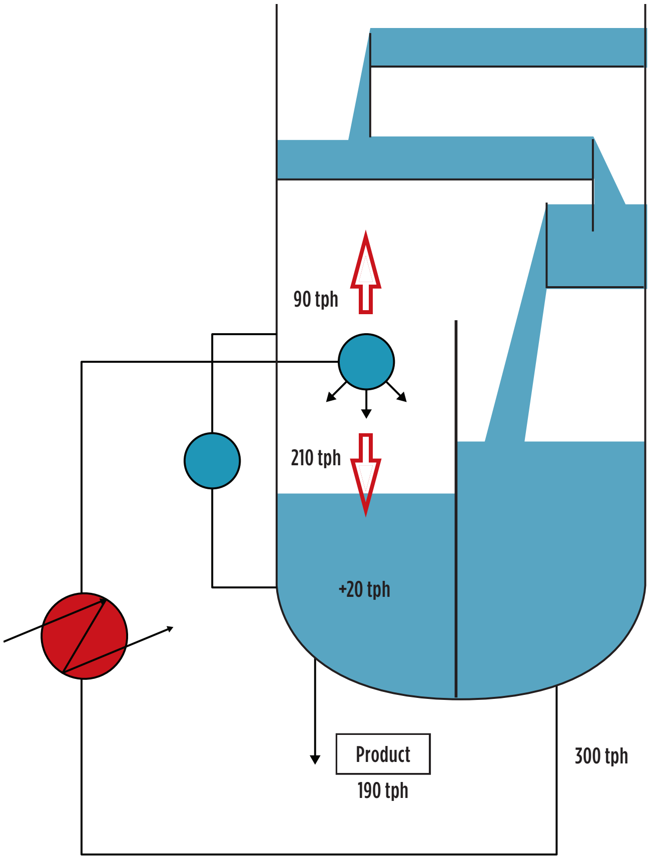

FIG. 3. An example of material balance issue (hydraulics).

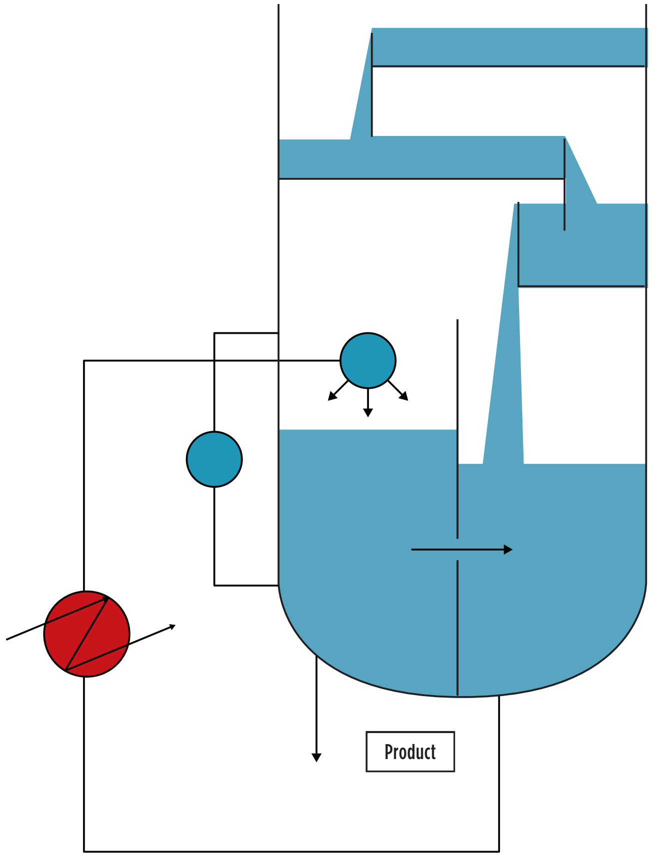

FIG. 4. Preferential baffle reboiler.

The second challenge faced during the startup of the column is starting the tower first on total reflux, so direct feed-in can begin whenever upstream is ready. Total reflux means there is no feed to the tower and no product withdrawn, only circulation with inventory. When the feedrate to the reboiler from the bottom tray is lower and the liquid thrown by the reboiler return (effluent) to the other compartment is higher (reboiler intake from one compartment and return to the other), the level in the reboiler compartment is depleted and this compartment will dry. Reboiler return goes to the product compartment and its level increases continuously. So, the level of reflux drum level will reduce and the bottom would fill up. One solution is to have an equalization line to equalize the liquid in both compartments during the total reflux run. This solution is provided by Kister.[4]

To avoid these two problems, many designers put a hole in the bottom baffle, which is called a preferential baffle. This means the reboiler has the ability to take liquid from both compartments. This solution is a combination of a once-through and a circulating reboiler. The theoretical separation efficiency of the preferential reboiler is higher than a circulating reboiler and lower than once-through reboiler.[6] This preferential baffle provides operational flexibility during the startup of the column running on total reflux. This hole in the baffle (which makes it preferential) equalizes the level in both compartments. This baffle does not need any seal welding or to be fully tight.

FIG. 4 shows the configuration of the preferential baffle. In the baffle, there is a man-way to inspect both sides of the baffle, but it should be tight at the time of box-up before startup. In some plants—to make it a preferential baffle—the man-way of this baffle is often open to equalize the level. However, this is an incorrect methodology.

An accurate hole size matters in the preferential baffle. The direction of flow must always be from the product compartment to the reboiler compartment. This will reduce the LMTD slightly, but the bottom product composition will be unaffected. If the hole diameter (size) is larger than normal, then flow can be from the reboiler compartment to the product compartment and lighter liquid can go with the bottom product and pressurize the downstream. If the hole diameter is smaller than normal, then the liquid can accumulate and disturb the bottom level. The hole size should be such that liquid always flows from the product sump to the reboiler sump. The liquid level in the product compartment should be 4 in.–5 in. higher than the reboiler compartment.

The elevation of the hole in the baffle can also make a difference in design. The elevation of the hole should be such that the head of the thermosyphon reboiler is always maintained. As the withdrawal of product increases, the level is reduced and liquid can flow from the reboiler to the product compartment. The elevation and size of the hole should be calculated based on liquid hydraulics and the required head of the thermosyphon reboiler.

For preferential baffle reboiler designs, one additional level gauge or level transmitter should be provided to ensure the level in the reboiler inlet compartment.

Takeaway. The proper design of a preferential baffle reboiler can avoid startup and liquid accumulation issues, which can potentially destroy the whole column. As noted by Kister,[7] 50% of column problems were due to level accumulation and reboiler return nozzle submerging in the liquid. The bottom sump design must be checked during the design stage. This may reduce 50% of the issue before it happens.

Part 2 will appear in the May issue. HP

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LEE NICHOLS, Editor-in-Chief/Associate Publisher

The 1950s: Capacity expansion, HDPE/PP, polycarbonate, computers and rocket science

The 1950s marked an evolution in the use of oil by nations around the world. The processing of crude oil into fuels (e.g., gasoline and aviation gasoline) was imperative for economies to function—the use of oil increased significantly in many countries' total energy mix. For example, the use of oil was imperative during reconstruction efforts in Western Europe post World War 2 (WW2). Petroleum products in Europe's total energy mix increased from 10% at the end of WW2 to 21% in the mid-1950s and upwards to 45% in the 1960s.[68]

Across the world, nations were investing in new refining capacity to satisfy demand for refined fuels. One of the first refineries to startup post WW2 was the Ras Tanura refinery in Saudi Arabia—the refinery began operations approximately 1 mos (October 1945) after the end of the global conflict. By the early 1960s, the Ras Tanura refinery expanded production capacity from 50,000 bpd to 210,000 bpd.[69] Additional refining capacity increased in other nations and regions, including India, southeast Asia, the U.S., Western Europe and the first refineries in Africa—two refineries were built in Algiers, Algeria and Durban, South Africa in 1954, followed by refinery construction in Angola, Ghana, Nigeria and Senegal in the late 1950s/early 1960s.[70]

The 1950s was also a time of new technological discoveries for the refining and petrochemical industries. These included new refining and petrochemical processes to produce higher octane fuels, new derivatives of polyethylene (PE), the evolution of catalyst design, new chemical products, the adoption of computers in plant operations and the advancement of rocket fuels technology.

FIG. 1. Phillips Research Complex. The inset shows the site of the development of PP. Photo courtesy of American Chemical Society and Phillips 66 (successor of Phillips Petroleum Co.).

Catalytic research and development advances. After WW2, demand for high-octane gasoline increased globally—fluid catalytic cracking (FCC) capacity witnessed a significant capacity buildout in the 1940s to produce high-octane fuels for the Allied war effort. In turn, researchers developed new technologies to advance refining processes to produce higher octane fuels. For example, the U.S. added approximately 4 MMbpd of octane improvement capacity (e.g., catalytic reforming, isomerization, alkylation, hydrotreating)—directly or indirectly—during the 1950s.[71] Another process—Platforming, invented in the late 1940s by Vladimir Haensel of UOP—was instrumental in the eventual removal of lead from gasoline. The process also used a platinum catalyst to produce gasoline with a higher octane rating, an unconventional approach at the time due to the high costs of precious metals. Around the same time, hydrodesulfurization was commercialized. Today, most refineries have one or more desulfurization units.

In the 1950s, FCC processing technology started to incorporate zeolite catalysts in the reaction. Due to their molecular structure, zeolite catalysts are extremely effective in the reaction process—they have higher performance at lower pressures. In the early 1960s, the effectiveness of zeolite catalysts was also instrumental in making the hydrocracking process economical—the modern hydrocracking process was developed at Standard Oil of California's (now Chevron) Richmond

refinery in 1959; the refinery also installed the first paraxylene unit in the U.S. in 1954. Within 10 yr, global hydrocracking capacity increased by a factor of 1,000, reaching approximately 1 MMbpd.[72]

High-density polyethylene, polypropylene and Ziegler-Natta. In 1951, J. Paul Hogan and Robert L. Banks were conducting catalyst research at Phillips Petroleum Co.'s research complex (**FIG. 1**) in Bartlesville, Oklahoma (U.S.). According to literature[73], they set up an experiment using a nickel oxide catalyst but included small amounts of chromium oxide. In addition, they fed propylene, along with a propane carrier, into a pipe packed with catalyst. The result was that the chromium had produced a white, solid material. The two chemists had produced a new polymer: crystalline polypropylene (PP).[73]

While using the same chromium catalyst, Hogan and Banks conducted research to produce a new ethylene polymer. Within a year, the two chemists discovered a new process that used far less pressure than the PE process invented by Imperial Chemical Industries in England. **Note:** The History of the HPI segment published in the February issue of *Hydrocarbon Processing* provided a detailed history of the discovery of PE in the 1930s. Hogan and Banks' process required only a few hundred pounds per square inch (psi) vs. the PE process that required 20,000 psi–30,000 psi.[73] The new process produced a high-density polyethylene (HDPE). The discovery of HDPE and PP launched the Phillips Petroleum Co. into the global plastics market. The company marketed their new discovery under the name Marlex. The new polyolefin product line became immensely popular as the basis for a toy developed by Wham-O. The toy maker used Marlex to produce a round plastic tube they sold under the name Hula Hoop.[74]

Around the same timeframe, more than 4,700 mi from the Bartlesville research lab, German chemist Karl Ziegler was experimenting with ethylene at the Max Planck Institute for Coal Research in Germany. Ziegler's goal was to synthesize PE of a high molecular weight. However, each reaction was unsuccessful due to contamination of nickel salt.[75] After testing several different metals to counteract nickel salt contamination, he discovered titanium-based catalyst was immensely successful at accelerating the reaction process. Ziegler's discovery led to a new process to produce PE without using high pressure and temperature. He also discovered that the produced PE consisted of very ordered, very long, straight-chain molecules (**FIG. 2**).[76]

Italian chemist Giulio Natta (**FIG. 3**) heard about Ziegler's discovery while working at the Italian chemical company Montecatini. After Montecatini purchased the commercial rights to Ziegler's new catalyst in Italy, Natta proceeded to conduct research on Ziegler's work, focusing not on ethylene like Ziegler but on propylene polymerization. Through these endeavors, Natta successfully produced isotactic PP, which Montecatini began to produce on a commercial scale in 1957. By x-ray investigations, Natta was also able to determine the exact arrangement of chains in the lattice of the new crystalline polymers he discovered.[77]

Ziegler and Natta's research and development on catalyst polymerization became known as Ziegler-Natta catalyst. For their work, both men were awarded the Nobel Prize in Chemistry in 1963. This catalyst is still in use today for polymer production.

Through the work of Hogan, Banks, Ziegler, Natta and other professionals aid-

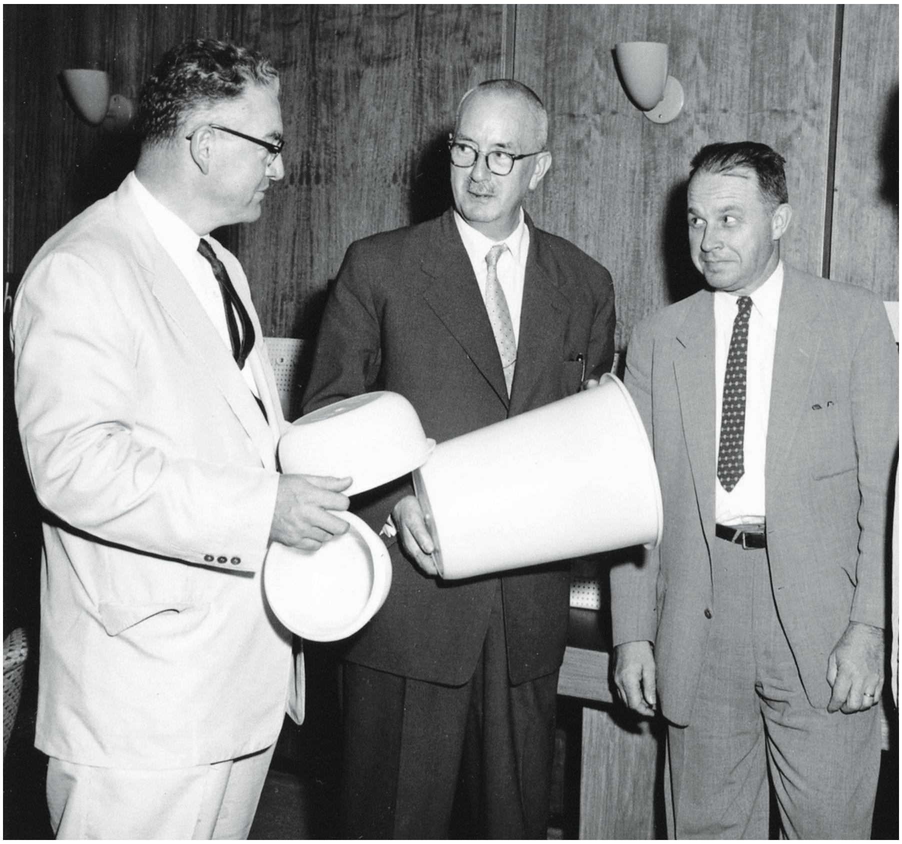

FIG. 2. Karl Ziegler (center) with members of the Hercules group that commercialized HDPE as Hi-fax. Photo courtesy of Hercules Inc. The company was acquired by Ashland Global Specialty Chemicals Inc. in 2008.

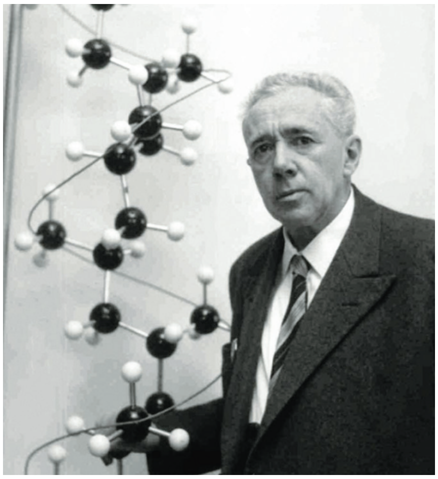

FIG. 3. Giulio Natta was awarded the Nobel Prize in Chemistry in 1963 for his work on propylene polymerization. He shared the prize with Karl Ziegler. Photo courtesy of Maire Tecnimont.

ing in the research and development of these chemists, HDPE and PP have produced new products used extensively in many different applications, raising the standard of living for people around the globe. Since being discovered in the 1950s, both PP and HDPE have witnessed their market value surge over the past 70 yr, eclipsing \$100 B and \$70 B, respectively.

Commercialization of polycarbonate and emulsion technology. Although first discovered in the late 1890s, polycarbonate did not find commercial use until the late 1950s. The polymer was first created by German chemist Alfred Einhorn while working at the University of Munich in 1898. Dr. Einhorn is best known for synthesizing the local anesthetic procaine, which became known as Novocain, a numbing agent primarily used in dental procedures—prior to his discovery, cocaine was a commonly used local anesthetic which had undesirable side effects, including toxicity and addiction.[78,79] According to literature, Dr. Einhorn was attempting to synthesize cyclic carbonates and produced polycarbonate by reacting hydroquinone with phosgene.[78] However, no commercial use was found for this material.

Approximately 30 yr later, Wallace Carothers and his research team at DuPont created polycarbonates while working on the development of polyesters and nylon. An account of these discoveries—polyesters and nylon 66—are detailed in the History of the HPI segment published in the February issue of *Hydrocarbon Processing*. However, Carothers' team did not find a commercial use for the produced polycarbonates.

In 1953, a commercial use for polycarbonates was discovered almost simultaneously in two different parts of the world—this year also marked the first iteration of the Petrochemicals Process Handbook (published in the November issue of *Petroleum Refiner*, the forerunner to *Hydrocarbon Processing*), which detailed emerging petrochemical processes. While researching polycarbonates at Bayer's (the company's Material Science division became Covestro in 2015) research and development laboratories in Uerdingen, Germany, Dr. Herman Schnell created the first linear polycarbonate.[80] Approximately 1 wk later, Dr. Daniel Fox also discovered the same compound while conducting research on new wire-insulating material at General Electric (GE) in Schenectady, New York (U.S.).[81] Both Schnell's and Fox's polymer were chemically the same but differed structurally—i.e., Schnell's polymer was a linear polycarbonate and Fox's polymer was a branched material.[78,81]

Both Bayer and GE filed for U.S. patents in 1955, leading to legal challenges on the rightful owner of the technology. Bayer was awarded the patent; however, the two companies agreed that the patent holder would grant a license for an appropriate royalty. This agreement allowed both companies to develop and market their own polycarbonate technology.[82] Bayer began marketing their product in 1958 under the trade name Makrolon. GE began commercial production in 1960 and marketed their product under the name Lexan—the GE Plastics division was created in 1973, later being acquired by the Saudi Arabian chemical company Saudi Basic Industries Corp. (SABIC) in 2007; SABIC divested the subsidiary (known as the Polymershapes business) in 2016.[83]

Over the next nearly 70 yr, polycarbonate has evolved and is used in a multitude of products for everyday life. The tough plastic is used in many applications that require transparency and high impact resistance. These include in the production of windows, protective eye wear, electronic components (e.g., electrical and telecommunications hardware), construction materials, materials within the automotive and aviation industries, and other niche market applications.[81]

The late 1940s/early 1950s also witnessed the advancement of acrylic emulsion technology. The technology

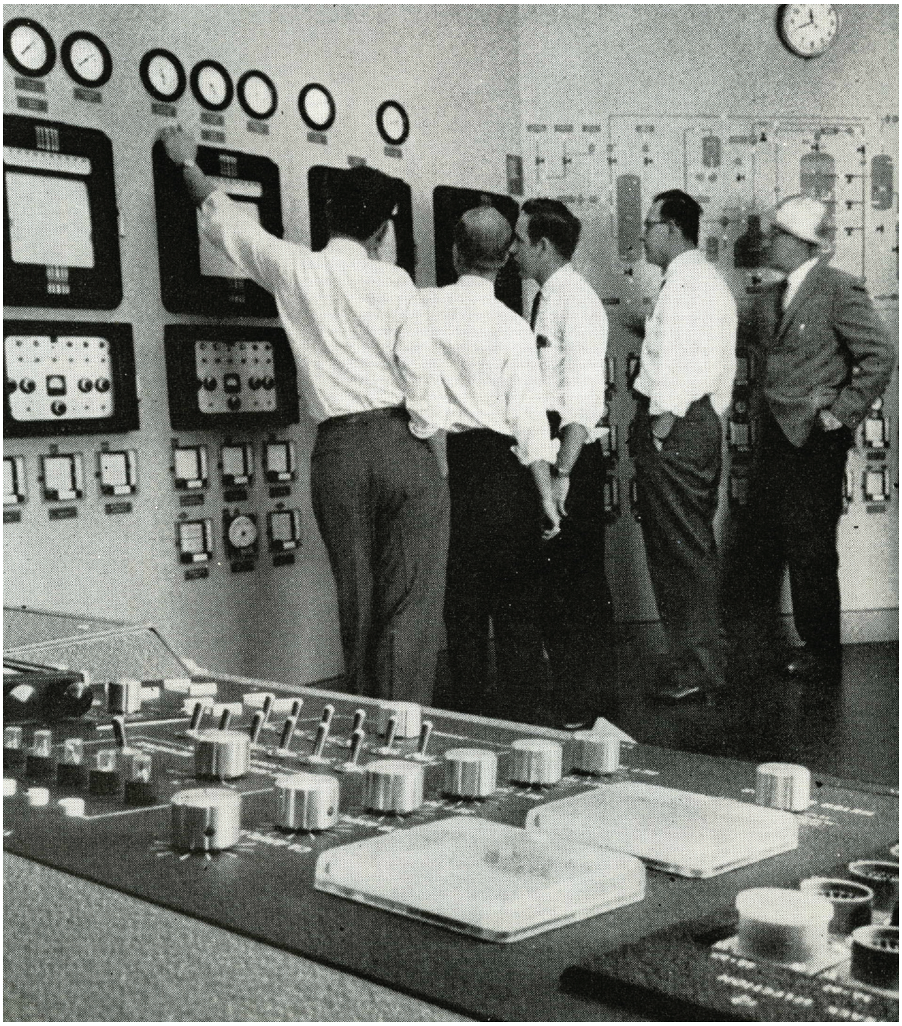

FIG. 4. The RW-300 computer system, foreground, was used to enhance operations at Texaco's Port Arthur refinery's 1,600-bpd polymerization plant. In the background, Texaco engineers and TRW personnel check control charts. Photo courtesy of *Business Week.*

was invented by scientists at Röhm and Hass—the company, founded in Esslingen, Germany by Dr. Otto Röhm and Otto Haas in 1907, invented Plexiglas (this discovery is detailed in the February issue of *Hydrocarbon Processing*).

To find a new product to market, the company's research department, led by Harry Neher, conducted experiments on acrylic monomer synthesis. The research built on earlier work by I. G. Farben (German chemical and pharmaceutical conglomerate) scientist Walter Reppe. After modifications, Neher invented a new semi-catalytic process called the F Process, which resulted in the production of vast qualities of cheap acylate monomers.[84] However, the company did not know exactly what to do with their newfound discovery.

One idea came from two scientists at the company, Benjamin Kline and Gerald Brown. They suggested the aqueous emulsion technology could make a great house paint.[84] At the time, most paints were solvent paints; however, they emitted an odor, were toxic and flammable, and hard to clean up. In 1951, Röhm and Hass built an F Process plant in Houston, Texas (U.S.) and produced their first paint emulsion product in 1952—it was named Rhoplex AC-33. The product had several benefits vs. solvent-based paints: it had a low odor, was easy to clean up, had a resistance to cracking and was environmentally friendly.

Röhm and Hass perfected the product over the next two decades, introducing a range of exterior and interior paint products with different finishes (e.g., flat, semi-gloss and gloss). By the early 1970s, Rhoplex AC-33 surpassed Plexiglas sales for the company and created a new line of acrylic paints to rival solvent-based paints.

FIG. 5. Goddard standing next to his rocket. On March 16, 1926, he successfully launched the world's first liquid-propellant rocket. Photo courtesy of the U.S. Smithsonian National Air and Space Museum.

Closing the loop: The computer-integrated manufacturing era begins. On April 4, 1959, Texaco started operations on the first direct digital control computer at a refinery. The system—a Thompson Ramo Wooldridge (TRW) RW-300 computer—was installed on the company's 1,600-bpd polymerization unit at the Port Arthur refinery (Texas, U.S.). The initiation of this system "closed the loop" in the first fully automatic, computer-controlled industrial process.[85]

The installation of the system began several years before startup. TRW and Texaco engineers worked for more than 2.5 yr on a feasibility study for converting the plant to full automation. The 318-pg report provided robust detail on all actions the system would have to monitor. This analysis provided a basis for Texaco engineers to design the instrumentation and control system for the unit.[86] The initial goal of the computer system—which totaled approximately $300,000 (computer, instrumentation, labor and other equipment),[86] nearly $2.9 MM today after adjusting for inflation—was to raise the plant's efficiency by 6%–10%.

The work of the computer was described succinctly by Texaco's Chief Process Engineer, Charles Richker. "It gets an analysis of incoming gas and outgoing gas; it senses and measures pressure, flows and temperatures; it calculates catalyst activity; then it weighs all these together and decides what the processing unit should do to get the most product for the least cost," said Richker. "Finally, it sets the controls and rechecks its figuring."[86] The computer accomplished these tasks in a matter of seconds.

The RW-300 computer was able to accomplish more measurements, faster than refining personnel could ever hope to achieve. From literature, for example, the computer could read dozens of recorder-controllers that indicated pressure, temperature and flow, and then relate the readings that indicated the level of activity of the reaction or condition of the catalyst. The computer could then calculate the complex interrelationships of the process, all in time to reset the controls to keep the plant operating at maxi-

mum efficiency. The computer could conduct these readings every 5 min, 24 hr a day (**FIG. 4**).[86]

The success of the computer system led to the adoption of numerous installations over the next several years. The second RW-300 computer for the processing industry was installed at Monsanto's Chocolate Bayou, Texas (U.S.) petrochemical plant in 1960, followed by B. F. Goodrich's chemical plant in Calvert City, Kentucky (U.S.). Several other installations of the RW-300 occurred in the early 1960s, including at BASF's plant in Ludwigshafen, Germany; Gulf Oil Co.'s catalytic cracking plant in Philadelphia, Pennsylvania (U.S.); Petroleum Chemicals' ethylene plant in Lake Charles, Louisiana (U.S.); among others.[87]

IBM introduced its first multi-purpose industrial control system—the IBM 1710—in March 1961. The computer—which cost $111,000–$135,000 ($1 MM–$1.27 MM today after adjusting for inflation)—was used for a variety of sampling and the interpretation of data in the processing and manufacturing industries, including quality control, industrial process study and process optimization.[88] The system was first installed at American Oil's Whiting refinery in Indiana (U.S.) in 1961, followed by additional installations at Standard Oil of California's El Segundo refinery in Richmond, California (U.S.) and DuPont's acrylonitrile pilot plant in Gibbstown, New Jersey (U.S.) in the same year.[86,87]

From the late 1950s to the early 1960s, more than 40 computer control systems were installed in the chemical and petroleum sectors.[87] Although initially expensive, the use of computer systems revolutionized hydrocarbon processing operations and provided significant benefits to operating personnel and plant production. This period—later known as the computer-integrated manufacturing era for the hydrocarbon processing industry—transitioned the refining and chemical industries into a new computer age. Computer systems would continue to evolve over the next several decades, providing new enhancements and benefits along the way.

Rocket designs/fuels evolve, and the space race begins. Production of various fuels and gases have been instrumental in the development of space exploration and satellite technologies, especially in the construction of artificial satellites (e.g., Kevlar, invented in the 1960s by DuPont, help protect satellites in orbit from the harsh conditions of space) and propulsion. Although the origins of rocket propulsion go back several centuries (the Chinese used tubes filled with gunpowder—called "arrows of flying fire"—to repel the Mongols during the battle of Kai-Keng in 1232),[89] modern rocket propellant technology traces its roots to the mid-1900s.

The era of modern rocketry began with theories derived from the Russian rocket scientist Konstantin Tsiolkovsky. His work *Exploration of Outer Space by Means of Rocket Devices*—published in 1903—put forth the idea of both utilizing rockets for space flight and using liquid propellant for rocket propulsion.[90] These ideas and his research on the subject inspired future scientists that would revolutionize rocket fuel development over the next several decades. For this, Tsiolkovsky is known as the father of modern astronautics.

The first successful liquid-fueled rocket test was conducted in 1926 by Robert Goddard. Throughout his research, Goddard discovered that using liquid fuel provided more acceleration vs. other forms of propulsion, such as gunpowder. His rocket design had the combustion chamber and nozzle at the top of a frame made up of two vertical tubes, which would then carry the liquid fuel (comprised of liquid oxygen and gasoline) from the tanks at the bottom to ignite the rocket.[91,92]

On March 16, 1926, in Auburn, Massachusetts (U.S.), Goddard's rocket blasted off the launchpad. The rocket flew for 2.5 sec and reached an altitude of 41 ft.[91] The launch proved that liquid fuels could be used to propel rockets, setting the stage for the evolution of rocket engine designs, which would eventually lead to the use of satellites and space exploration.

Although Goddard's discovery was revolutionary, he kept his findings mostly secret. His work was barely known until the U.S. Smithsonian published his theory *A Method of Reaching Extreme Altitudes.* However, several media outlets openly mocked his theories. For example, the *New York Times* dismissed Goddard's theories as lacking basic knowledge learned in high schools—the publication printed a correction in July 1969 as the Apollo 11 mission launched on its historic mission to the moon.[91]

In the late 1920s, the world's first large-scale experimental rocket program began under the leadership of the German rocket technology pioneer Fritz von Opel (nicknamed Rocket Fritz) and other associates, including Max Valier, who was one of the founders of the German Spaceflight Society (Verein für Raumschiffahrt).[93] The Opel RAK significantly advanced rocket and aviation technology, especially in propulsion. In 1928, the group developed its first liquid-fueled rocket, which used benzol—a coal-tar product consisting mainly of benzene and toluene—as fuel and nitrogen tetroxide as the oxidizer.[93]

The research and testing completed on Opel RAK led to the development of Germany's V-2 rocket, the world's first long-range guided ballistic missile powered by a liquid-propellant (liquid oxygen and ethyl alcohol) rocket engine. After WW2, several nations used the V-2 rocket technology to develop their own military missile programs, as well as advance space exploration. These initiatives were supported by hydrocarbon processing companies. For example, Air Products was commissioned by the U.S. to build plants that could supply large quantities of liquid oxygen and nitrogen to support the country's emerging missile and space program.[94] After Russia successfully launched Sputnik into space in 1957 (the satellite used kerosene T-1 as a fuel and liquid oxygen as an oxidizer[95]), Air Products was awarded a contract to supply liquid hydrogen to the U.S. Air Force—and later to NASA—to advance the country's rocket technology to compete against the Soviets during the Cold War and space race. The U.S. eventually created Rocket Propellant-1, which is a highly refined form of kerosene and liquid oxygen.

These fuels aided the advancement of rocket technology, leading humans to break the boundaries of space and place satellites into geosynchronous orbit, significantly evolving the way the world communicates, navigates and explores not only Earth but the distant cosmos. These advancements would not have been possible without the fuels and products produced from the hydrocarbon processing sector. HP

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SUMEDHA SHARMA, Technical Editor

Industry Pioneers: Cracking technology, catalysts, polymers and zeolites

DONALD L. CAMPBELL, EGER V. MURPHREE, HOMER Z. MARTIN AND CHARLES W. TYSON




Donald Campbell, Eger Murphree, Homer Martin and Charles Tyson—often called the ‘Four Horsemen’—are credited with the landmark invention of fluid catalytic cracking (FCC). The FCC process revolutionized the refining industry by providing an efficient process to increase the yield of high-octane gasoline from crude oil. Their invention was awarded a U.S. patent and described as ‘a method of and apparatus for contacting solids and gases.’[1]

During the late 1930s, Exxon Research & Engineering Co. (ER&E) was looking for ways to improve high-octane gasoline yield. Chemical engineering professors at MIT—Warren K. Lewis and Edwin R. Gilliland—suggested that a low-velocity gas flow through a powder may lift it enough to cause it to flow like a liquid.[1] Campbell, Martin, Murphree and Tyson at ER&E focused on the idea of a fluidized catalyst to innovate a design that would ensure a steady and continuous cracking operation. This idea led the four inventors to design a fluidized solids reactor bed with a pipe transfer system between the reactor and regenerator unit in which the catalyst is decoked and regenerated for reuse. The solids (catalyst) and gases (vaporized oil) are in continuous contact as they move upward in fluidized flow while cracking occurs. The hydrocarbon chains are split into smaller pieces, and the cracked molecules are further distilled to produce gasoline, heating oil, fuel oil, propane, butane and chemical feedstocks that are instrumental in producing a variety of petrochemical products.

The four inventors developed the process in 1942, and the first commercial FCC facility went online on May 25, 1942.[2] Their invention was not only extremely important but also timely, as it enabled refineries to produce and supply enough high-octane fuel to aid U.S. and Allied forces during World War 2 (WW2). FCC technology also led to the rapid buildup of butadiene production, which was used by ER&E for making synthetic butyl rubber, another technology that was vital during that era. The first commercial FCC plant processed 13,000 bpd of heavy oil, making 275,000 gal of gasoline.[3] FCC is widely employed today around the world and continues to evolve as the market for high-performance clean fuel demand increases.

Donald Campbell was an American engineer who was always fascinated by inventing and solving problems. He attended Iowa State University, then MIT and the Harvard Business School. He worked for 25 yr at ER&E, with a total of 41 yr at Exxon. He retired as Assistant to the Vice President of New Areas of Research, with 30 patents to his credit.[3]

Eger Murphree, a graduate in chemistry and a teacher, joined Standard Oil of New Jersey (later ER&E) in 1930. With his phenomenal work at ER&E and as co-inventor of FCC technology, he rose to serve as the President of ER&E from 1947–1962.[4] He is widely recognized as a leader in the field of synthetic toluene, butadiene and hydrocarbon synthesis, FCC and fluid hydroforming.[4]

Homer Martin was a chemical engineer who earned a BS degree from the Armour Institute and an MS and PhD from the University of Michigan. He joined ER&E in 1937 and became one of the most productive inventors, garnering 82 patents until his retirement in 1973.[5]

Charles Tyson received his BS and MS degrees in chemical engineering from MIT and joined ER&E in 1930. He was the Director of the Petroleum Development Division and later the Special Assistant to the Vice President of ER&E. His work, primarily focusing on petroleum processing, earned him more than 50 patents until his retirement in 1962.[2]

ROBERT BANKS AND PAUL HOGAN

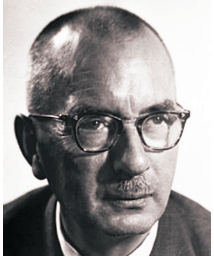

American research chemists J. Paul Hogan and Robert Banks discovered crystalline polypropylene (PP) and created a process for making high-density polyethylene (HDPE) while working at Phillips Petroleum in 1951.[6] Their breakthrough invention, although serendipitous, was not accidental. In the wake of WW2 and diminishing oil demand,

Phillips Petroleum was involved in concerted efforts to investigate the uses of natural gas liquids (NGLs). Hogan and Banks were studying processes by which propylene and ethylene could be converted to valuable gasoline-like materials, so they started investigating the use of catalysts to do so.

In June 1951, they were experimenting by adding a small amount of chromium oxide to a nickel oxide catalyst and fed propylene with a propane carrier through the catalyst-packed tube. While pure nickel oxide yielded the expected product of low-molecular weight hydrocarbons, the chromium-modified catalyst produced a white solid—a new material, crystalline PP. With this new discovery, they pivoted research efforts from gasoline to plastics and used the chromium catalyst to produce an ethylene polymer. Within a year, they created the process for making HDPE—the safest, hardest and most heat-resistant plastic created at the time using much lower operating pressure than branched low-density PE. Phillips launched their product as Marlex® in 1954.[7] Their invention revolutionized the consumer plastics industry and launched Phillips, an oil company, as a manufacturer of polyolefin plastics. HDPE is extensively used in packaging, commodity plastics, toys, tools, furniture, auto parts and a variety of other applications.

Hogan received the Pioneer Chemist Award and is credited with 52 U.S. patents.[8] Hogan and Banks together received the Perkin Medal in 1987, the Heroes of Chemistry award by the American Chemical Society in 1989 and were inducted into the National Inventors Hall of Fame in 2001.[9]

KARL ZIEGLER



In 1953, German chemist Karl Ziegler employed a catalyst consisting of a mixture of titanium tetrachloride and an alkyl derivative of aluminum to create a high molecular weight, high melting point and straight-chain PE. His pioneering research with organometallic compounds, which made industrial production of high-quality PE possible, won him the 1963 Nobel Prize in Chemistry, which he shared with Giulio Natta.[10]

Ziegler's research established new polymerization reactions; enabled the syntheses of durable, higher melting, unbranched polymers; and laid the groundwork for several useful industrial processes. He combined classical organic chemistry with physical and analytical experimental methods in his phenomenal work on polymerization reactions.

Ziegler began his work on carbon compounds and organometallic chemistry during his professorship at the University of Heidelberg, which he continued after joining as the Director of the Max-Planck-Institut in Mülheim in 1943.[11] Between 1952 and 1953, Ziegler's research group tested various organoaluminium compounds and discovered that nickel was the cause of the chain-ending reaction. They further investigated to find a reagent to suppress this chain termination reaction, which led them to discover that titanium, under mild atmospheric conditions, produced rigid, high-melting unbranched PE.

Besides his work with organometallic compounds, he is also known for his research in the field of radicals with trivalent carbon and synthesis of multi-membered ring systems, which earned him the Liebig medal in 1935.[11] One of the many awards Ziegler received was the reputed Werner von Siemens Ring in 1960 for expanding the scientific knowledge of and the technical development of new synthetic materials.[10] Ziegler was able to take his discovery to industrial markets. By 1958, he was reaping the benefits of approximately two dozen licenses.[12]

GIULIO NATTA

Giulio Natta, an Italian scientist and chemical engineer, extended Ziegler's method to other olefins. Based on his own findings on the reaction mechanism of polymerization, he developed further variations of the Ziegler catalyst. For his contribution to the field of high polymers, he shared the Nobel Prize in Chemistry with Karl Ziegler in 1963.[13] Commercial Ziegler-Natta catalysts include many mixtures of halides of transition metals, especially titanium, chromium, vanadium and zirconium, with organic derivatives of nontransition metals, particularly alkyl aluminum compounds.[14]

Natta's early research career focused on studying solids by x-rays diffraction (XRD) and electron diffraction. He later employed the same expertise to study catalysts and the structure of high organic polymers. By 1938, he began investigating macromolecules—polymerization of olefins and the kinetics of subsequent concurrent reactions.[15] In 1953, after he received financial aid from the large Italian chemical company Montecatini, he extended Ziegler's research on organometallic catalysts to stereospecific polymerization.[15] These studies led to the development of isotactic PP, a thermoplastic polymer of highly regular molecular structure with commercially important properties of high strength and a high melting point. In 1957, Montecatini produced this polymer on an industrial scale at their Ferrara plant.[15] Natta's creation was commercially marketed as a plastic material by the name of Moplen, as a synthetic fiber by the name of Meraklon, as a monofilament by the name of Merakrin, and as packing film by the name of Moplefan.[15]

Natta discovered new classes of polymers and used XRD to determine the exact arrangement of chains in the lattice of the new crystalline polymers he discovered. He created polymers with sterically ordered structure—isotactic, syndiotactic and di-isotactic polymers and linear nonbranched olefinic polymers and copolymers with an atactic structure.

Natta is also known for his later research that led to two different routes for the synthesis of new elastomers: by polymerization of butadiene into *cis*-1,4 polymers with a high degree of steric purity, and by copolymerization of ethylene with other a-olefins (propylene), originating extremely interesting materials such as saturated synthetic rubbers. Natta published 700 research papers of which about 500 focus on stereoregular polymers. He also received several awards and has many patents in different countries to his credit.[15]

HERMAN SCHNELL

Dr. Hermann Schnell was a German scientist at Bayer who discovered the synthesis reaction of a new plastic—polycarbonate from co-monomers bisphenol A and phosgene. The new thermoplastic polymer—polycarbonate—has superior strength, toughness and impact resistance. Despite its resistance to breaking and splintering, it is lightweight, mostly optically transparent and can be easily molded or thermoformed. Unlike most thermoplastics, it can undergo large plastic deformations without cracking or breaking. With these properties, it is used in a variety of daily applications such as construction materials; electronic, auto, aircraft and security components; and optical lenses.[16]

Schnell studied under Nobel laureate and chemist Herman Staudinger. Soon after graduating, he joined the research and development department at Bayer AG, Leverkusen, Germany. Shortly thereafter, he moved to the lab at Uerdingen where he and his research team discovered the synthesis reaction of polycarbonate. The official patent for polycarbonate synthesis was granted in 1953 and was registered under the brand name Makrolon® on April 2, 1955.[17] Bayer started industrial-scale production of Makrolon® at its plant in Uerfingen, Germany in 1958.[17]

Schnell became the department leader at Bayer research at just 36 yr of age and was appointed department head of Bayer's entire central research facility in Leverkusen in 1971. He retired from Bayer in 1975.[17]

FREDERICK W. STAVELY

Frederick W. Stavely was a chemical research scientist who is credited with the discovery of polyisoprene. Stavely was a researcher at the Firestone Tire & Rubber Co in 1953 where, while investigating the reaction of butyl lithium on butadiene, he discovered that the polymerization of isoprene with metallic lithium produced polyisoprene with high *cis* content. High *cis* content is indicative of enhanced strain crystallization, which is closer to natural rubber, also with high *cis* content. This discovery was important during WW2 because other synthetic compounds did not exhibit the crystallization effect that was achieved in Stavely's process. Stavely served as Chairman of the American Chemical Society Rubber Division. In 1972, Stavely received the Charles Goodyear Medal in recognition of this discovery.[19]

EDITH MARIE FLANIGEN

Edith Marie Flanigen, an American chemist, is known for her synthesis of zeolites for molecular sieves. Molecular sieves are crystalline microporous structures with large internal void volumes and molecular-sized pores that can separate or filter complex mixtures, as well as function as catalysts for chemical reactions. These compounds find numerous applications in the refining and petrochemical industries.

Flanigen joined Union Carbide in 1952 and began working on molecular sieves in 1956.[20] During her 42-yr career at Union Carbide and UOP, Flanigen invented or co-invented more than 200 novel synthetic materials but is best known for her substantial contributions to the development of zeolite Y, an aluminosilicate sieve used to make oil refining more efficient, cleaner and safer.[21] Zeolite Y is essentially employed in the cracking of crude oil to produce commercially valuable products like gasoline and diesel in a cleaner and more efficient manner. Her invention finds application in purification and contaminant removal and can be used to make ethylene and propylene, which are important raw materials to the petrochemical industry.

Besides her work on molecular sieves, Flanigen co-invented a synthetic emerald and pioneered the use of mid-infrared spectroscopy for analyzing zeolite structures. She has been quoted to say that one of her strengths throughout her career has been her ability to discover new material and see it through to commercialization, from envisioning processes for manufacturing it on a large scale to developing it for industrial application.

Flanigen became the first woman to hold the position of Senior Corporate Research Fellow at Union Carbide in 1982. She retired in 1994 with 108 U.S. patents in the field of petroleum research and product development.[21, 22]

In 1992, she became the first woman to receive the prestigious Perkin medal, the most distinguished honor in applied chemistry.[22] Flanigen was the recipient of the $100,000 Lemelson-MIT Lifetime Achievement Award in 2004 and was inducted into the National Inventors Hall of Fame in the same year.[22] In 2014, President Obama presented Flanigen with the National Medal of Technology and Innovation for her contributions to science and technology.[22] HP

ACKNOWLEDGEMENTS

Hydrocarbon Processing would like to thank several institutions, companies and websites for the use of archived images of industry pioneers. These include the National Inventors Hall of Fame, the MIT Museum, the Plastics Hall of Fame and The Nobel Prize.

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LEE NICHOLS, Editor-in-Chief/Associate Publisher

Excerpts from the 1950s: Capacity expands after WW2 and technologies and maintenance mature

The following is a mixture of technical articles, columns and headlines published in the 1950s by *Petroleum Refiner,* the forerunner to *Hydrocarbon Processing.* This collection of excerpts provides a look into the major technological advancements and topics/trends in the hydrocarbon processing industry during that timeframe.

First postwar cargo of crude for rebuilt Dunkirk refinery received

February 1950

Progress in new British refinery

E. N. Tiratsoo, February 1950

The first unit of the Shell Oil Co. refinery near Stanlow has been completed and is in operation using crude oils from the Middle East.

Propylene, a valuable feedstock for alkylation

E. C. Oden, W. J. Burch and G. R. Jones, March 1950

Alkylates produced in refinery alkylation processes have high octane numbers, lead susceptibilities and heat values and boil in the gasoline range to rank among the most important components of aviation and motor gasolines. The reaction most widely used in the process has been the combination of isobutane and butylene.

This article provides data from the operation of a sulfuric acid alkylation unit, on propylene, and shows the effect of the major operating variables on aviation alkylate quality, alkylate yield and acid consumption.

The new metals—Molybdenum, titanium and zirconium

May 1950

Techniques for producing and fabricating these new metals are progressing rapidly, so that within the next few years, they should take an important place in industry, along with the other special metals such as stainless steel, super alloys, tantalum and others.

Pemex's Salamanca refinery is nearing completion

June 1950

The new $12-MM plant will help the geographical balance of Mexico's refining and marketing area by providing a 60% increase in refining capacity in the country.

Corrosion-resistant liners in refinery vessels

G. C. Carpenter, July 1950

The internal protection of refinery process vessels becomes increasingly important as throughputs are increased and crude oils become less sweet and saltier.

Bubble tray design and layout—Parts 1 and 2

J. A. Davies, August and September 1950

The bubble tray is possibly the most important single item of equipment used in petroleum processing plants. Despite the use of tens of thousands of these trays, both their initial design and their performance in operation present certain mysteries to engineers and operators alike.

In this series of articles, the author has organized the complete tray calculation problem into an orderly routine. He has attempted to provide sufficient information in practice, theory and procedure to allow a person without considerable experience to reach sound answers on bubble tray problems. Part 1 deals with the mechanical details of the bubble tray, while Part 2 covers the actual calculation of tray performance.

Work progresses on Europe's largest oil refinery

December 1950

Anglo-American Oil Co.'s $100-MM, 5-MMtpy refinery is nearly completed. The plant is being built in Fawley, Hampshire, England, approximately 15 mi southeast of Southhampton. Once completed, the facility will produce 42,500 bpd of crude naphtha and white spirit, 6,000 bpd of kerosene, 14,000 bpd of diesel fuels and gasoils, 6,000 bpd of light fuel oils, 30,000 bpd of bunker fuel and 3,500 bpd of asphalts.

Tuning automatic control systems

J. L. Serrill and L. E. Jewett, January 1951

This article describes a method by which plant instrument adjustments can be made in orderly sequence to attain optimum overall behavior of process units.

Maintenance facilities in gasoline cycling plants

H. Givens, April 1951

Downtime is a constant threat to even well-managed plants. However, carefully planning repair procedures can significantly mitigate such problems.

The petrochemical engineer looks at rocket fuels

M. Sittig, May 1951

The rocket-type aircraft engine appears to be susceptible to improvements in performance because of fuel development,

which can be expected to exceed those which have occurred with the piston-type aircraft engine.

In view of this, the petrochemical engineer should possess some knowledge of those materials currently in use as rocket fuels and of those materials which are potentially attractive as tomorrow's propellants.

The middle of the barrel comes of age

A. L. Nickerson, July 1951

There is an increasing need to shift oil refining operations from the emphasis on gasoline production to increasing the yield of middle distillates.

Refinery painting

W. B. Cook, March 1952

One of the most troublesome problems at every refinery is that of minimizing external corrosion. Gulf Coast refiners have developed a progressive program of corrosion control through systematic refinery painting.

In this article, the author discusses the many problems of surface protection through painting. Factors to be considered include the nature of the surface to be protected, the character of the exposure expected and the various paint materials available for protection.

Production of high-purity aromatics for chemicals

D. Read, May 1952

A combination of Platforming and Udex extraction provides the refiner with a tool for manufacturing high-purity aromatics.

Improved process polymerizes olefins for high-quality gasoline

G. E. Langlois and J. E. Walkey, August 1952

This article details an improved catalytic polymerization process is being licensed to produce high-quality gasoline from light olefins. The polymer is a 98-octane gasoline.

Techniques for cat unit turnarounds

J. G. Traxler and K. T. Beavers, February 1953

This article presents the complete details on how to conduct a turnaround, including a description on worker coordination.

Shale oil—What is it?

G. U. Dinneen, February 1954

This work provides analyses of 10 U.S. and 10 foreign shale oils yield in comparison with crude petroleum.

A look ahead in vessel design

E. W. Jacobson, November 1954

Lower initial cost and longer trouble-free life of pressure vessels are dependent on a better understanding of corrosion, brittle fraction, creep at high temperatures, graphitization and hydrogen penetration, among other items.

World demand expands faster

R. S. Spann, January 1955

Global petroleum demand is expected to reach more than 14 MMbpd in 1955, an increase of about 6.6% vs. 1954.

Turnaround scheduling

J. O. Thoen, March 1955

Allowable run length, worker availability and process commitments all play major roles in turnaround scheduling.

Carbon formation in cat cracking

P. B. Crawford and W. A. Cunningham, January 1956

This article details a method to estimate the effect of charging rate, process period and temperature on the quantity of carbon deposited on the catalyst in a catalytic cracking unit. In addition, a path is provided to use fixed-bed reactor data for estimating results with the same catalyst and charge in moving bed or turbulent fluidized reactors.

What causes hydrogen attack?

G. R. King, March 1956

Hydrogen attack takes many forms. Some of these are more serious than others. This article will help plant personnel recognize the various forms of hydrogen attack and plan the most economical maintenance program.

How to select the right pump motor

October 1956

Do you know when to use the normal inrush and when to use the low inrush motor? This comparison between speed-torque characteristics of pump and motor will help you decide.

Is your distillation column in balance?

W. D. Harbert, November 1956

The operation of a distillation column is more costly if it is not in balance. This article provides a non-mathematical discussion of column balance and how to achieve it.

Analog computers calculate heat transfer

R. S. Schechter, February 1957

The increased availability of computing devices has caused considerable interest in expanding the scope of problems which are adaptable to automatic computation. The purpose of this article is to point out the usefulness of the analog computer in solution of natural convection problems.

Future fields of elastomers

J. Bjorksten, March 1957

The outlook for elastomers is exceptionally bright because of low fabrication costs.

Here is data on propane fractionation

E. E. Smith and C. E. Fleming, July 1957

Some of the advantages of separating hydrocarbons according to their solubility in liquid propane are discussed in this article. These data are compared with separation by distillation.

What to do about corroding isomerization units

J. F. Mason and C. M. Schillmoller, July 1958

Even though the process aspects of butane isomerization have been discussed in several articles in recent years, little has been said about the corrosion problems associate with these units. The intention of this article is to review some of these problems and point out where corrosion has occurred or can

normally be expected to occur, so that this information may serve as a guide to those who have butane isomerization units in the design or planning stage.

Urea—The petrochemical to watch

L. F. Hatch, August 1958

Urea is one of the fastest growing petrochemicals, with a 270% production increase in 8 yr. It is a triple-threat petrochemical with a dynamic future for fertilizer, animal feeds and synthetic resins.

Alkylation—What you should know about this process

R. E. Payne, September 1958

This comprehensive article tells of the many factors that influenced the alkylation process and its products. It will focus on the commercial aspects of alkylation—plant designs, operating techniques and process variables. The article will also provide details regarding investment and operating costs, some octane blending data and process history.

A checklist for plant layout

J. F. McGarry, October 1958

Whether it is a refinery or petrochemical plant, the article provides tips that will help attain maximum flexibility and compactness at a reasonable initial cost.

Petroleum Refiner: The Oil Centennial Issue

January 1959

This issue of the *Petroleum Refiner* provided a detailed look at the past 100 yr of the oil industry. This included the history of refining and petrochemical discoveries and technologies, as well as a look at the current global demand for petroleum products.

Find the best air fin cooler design

E. U. Nakayama, April 1959

Plant personnel must compare investment costs with operating costs to come up with the best cooler design. This article provides a sample problem that details this notion in action.

Which acetylene removal scheme is better?

W. H. Stanton, May 1959

Which method of acetylene removal—absorption or hydrogenation—is the most economical? One method is economically superior to the other depending upon the following variables: plant size, byproduct value of acetylene and acetylene made per 100 lbs of ethylene produced. This article provides the economics of absorption vs. hydrogenation for removing acetylene from rich ethylene streams. HP

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The EPC executive's challenge and opportunity: Navigating the sustainability shift in capital projects

According to an industry report published by McKinsey and Co., accelerating the decarbonization of the U.S. economy to achieve net-zero targets by 2050 will require approximately $275 T of cumulative capital spending over the next 30 yr.[1] This reallocation of capital could, according to an analysis by Deloitte[2], deliver net economic gains by the late 2040s and add $3 T to the U.S. economy over the next 50 yr. To spur this activity from a financial viewpoint, leading capital funding institutions such as BlackRock, JPMorgan Chase and Barclays have signaled to the industrial community that they will be preferentially funneling their funding sources to those companies that demonstrate commitment to accelerated decarbonization.

Energy and chemical companies are reacting to reposition themselves. The past year has seen a significant shift in the strategy, planning and initiatives among the leading players in the process industries. In a survey the author's company completed in June 2021, 77% of companies believe that carbon dioxide (CO_2) mitigation leadership is perceived to provide a competitive advantage.[3] At the same time, 21% of the more than 200 companies surveyed predict a shift in capital spending of more than 20% over the next 5 yr, while another 48% of companies forecast that shift to be at least 5%.

Will the traditional engineering, procurement and construction (EPC) organizations—whose experience and corporate memory are around large energy, chemical and infrastructure projects—effectively pivot to take advantage of the new sustainable economy capital opportunities? Or will it be a new generation of innovative sustainable engineering companies that drive the future? Nearly all EPC organizations are taking up the challenge, and it is up to their leaders and key subject matter experts to successfully navigate the change. It is a tricky balancing act, requiring that the leadership of EPC firms not only execute tactics to pivot in the short term in which areas like energy efficiency, bio feedstocks and carbon capture are top of mind, but also prioritize a long-term strategy where areas like broader electrification, hydrogen economy value chain and advanced recycling become increasingly important.

Insight into EPC sustainability opportunities. The author's company wanted to learn more about how sustainability initiatives are translating into capital projects, and how EPCs and their clients—the asset owners—view the next 18 mos. In what sustainability areas are projects expected to be concentrated? How are companies organizing to react? What are the challenges? What are the opportunities? To do this, AspenTech and *Hydrocarbon Processing* conducted a global survey of process industry decision-makers. More than 185 companies responded to the survey. Respondents represented a cross section of the process industries: 10% represented integrated energy companies, 27% upstream and downstream, 17% chemicals and 25% engineering services. The rest were mining, pulp and paper, and power. Responses were global, with 27% of the respondents from North America, 18% from Europe, 28% from Asia, 10% from the Middle East, and the remainder from South America and Africa. Insights were indicative of where EPCs see the most opportunities with their sustainability initiatives. Those initiatives are the focus here.

Pivoting of capital project work toward sustainability has accelerated. EPC projects have pivoted substantially towards sustainability over the past 6 mos. Will they shift even more dramatically over the next 5 yr? Presently, 17% of respondents indicate that more than 40% of their project work is in the sustainability area. Within the next 5 yr, 57% of respondents believe that more than 40% of their work will be in the sustainability area. Work seems evenly split between new plant construction and modification of existing plants.

Similar questions were asked in the survey AspenTech conducted in June 2021 and the discrepancy is astounding. The perception of how much process industry capital project work will be in sustainability in the next 5 yr has roughly tripled! That is a significant perspective shift in less than a year.

Energy efficiency projects lead the pack, but hydrogen is not far behind. What specific initiatives are driving capital spending momentum? According to AspenTech and *Hydrocarbon Processing's* survey, energy optimization projects and hydrogen economy projects are cited as driving project awards by 50%. Sixty-one percent of EPCs say that they are offering, or ramping up to offer, energy efficiency project services, with 52% offering hydrogen asset design and EPC services, and 43% planning to offer carbon capture design services. The top six types of projects that survey respondents are seeing are hydrogen, carbon capture and storage and utilization, energy optimization, solar/wind generation assets, materials recycling, and bio feedstocks. Interestingly, bio-feedstocks and biofuels projects are further down the list.

Europe is leading the way in terms of investments in energy efficiency. Carbon taxes and government incentives in Europe are driving refiners and chemical manufacturers to invest in a systematic and broad scale-up in energy efficiency initiative deployments. Depending on the

asset and the process, further efficiency improvements of 15%–30% are possible and feasible for many sites. For example, two of Europe's largest downstream organizations decided to deploy the author's company's advanced adaptive process control across their enterprise to meet near-term carbon footprint reduction commitments. This is a much broader and more accelerated scale of deployment of this proven energy efficiency and carbon reduction technology than seen before.

There are still hurdles to leap. With the wide range of sustainability initiatives and directions the industry is taking, EPCs are facing a diverse basket of capital project opportunities. However, therein lies a challenge. How does a company pick the correct areas to focus their capabilities and expertise? The author had the opportunity to speak with one Chief Executive Officer (CEO) of a mid-sized EPC company in North America. He personally is spending a large fraction of his time working on the company's strategy to grow in the sustainability projects area. He believes his personal focus on this mission is critical for the future direction of the firm.

This reality is one of the key factors at play: sustainability project work is a strategic pivot and requires executive attention. For his company, as a mid-sized contractor with a strong reputation, business is significantly tied to ongoing relationships, dating back to multiple successful projects over the years. However, the challenge is to maintain that trusted relationship with clients and to assemble the right capabilities to be credible and to prove themselves again as the EPC of choice in new sustainability technology areas, such as bio-based feedstocks, carbon capture, hydrogen and new materials. It is a seller's market for technology experts and experienced practitioners in those areas. The largest EPCs are bent on assembling a critical mass of staff with the right skills, leaving smaller players with the task of building bench strength in an expensive free agent market.

To get the right strategic focus on sustainability projects, just under half of the responding companies have set up a separate organization or division to pursue and perform sustainability projects. The other half are not yet taking that route. The author spoke with a group of key executives at another EPC that has made the decision to set up a separate group for sustainability projects. The group is set up under a separate executive reporting to the CEO. This approach can win in terms of getting the right executive focus and direction. It also provides a more transparent way to measure the progress in building the capabilities and execution success, as well as be successful in mapping directly to clients' focus on sustainability. Of course, the counter argument is that nearly all future projects will have some sustainability content, and that this distinction in some ways will not make sense in the future.

Closing the skills gap is top of mind. Regardless of what format of business development is chosen, this survey also sought to find out what the biggest barriers to sustainability capital projects execution are, as perceived both by the EPCs and owners. Building a staff of engineers with the right domain expertise was cited as a barrier by 45% of the respondents, the second largest barrier beyond the economics of the projects themselves.

In terms of how to build up the right staff capability in today's environment, also known as addressing the skills gap, companies are pursuing a range of approaches. Fifty-four percent of companies are increasing investment in in-house sustainability design training. Forty-two percent are incentivizing their staff to take supplemental sustainability design training, 30% plan to hire recent engineering graduates whose coursework has increasingly focused on sustainability aspects, and 34% are seeing the need to invest in software tailored to addressing the new design and economic challenges of sustainability projects.

New partnerships are emerging. Sustainability initiatives are driving new types and levels of partnerships. This is due to a few factors, including managing risks of new technology (e.g., CO_2 capture and green hydrogen among multiple participants) and extended value chains. For example, in a recent forum, Eni's Chief Operating Officer for Energy Evolution provided two examples of new partnership types. One example is CO_2 capture, in which companies with old hydrocarbon reservoirs that can store CO_2, and have the technical ability to do so, will collaborate with industries—such as steel—that are hard to decarbonize to develop joint solutions. Another example is biofuels, where land owners that produce biomass to supply biorefineries can combine with local employment initiatives in emerging economies such as central Africa. This will address multiple sustainable objectives simultaneously.

These and other types of partnerships will require EPCs to improve how they are using digital technologies. Partnerships require digital collaboration of many aspects of a design and an asset's data, far beyond what process industry players are accustomed to. Fifty percent of companies say they are pursuing owner-engineer partnerships. Forty-two percent are looking at cross industry partnerships, such as between upstream companies and metals refiners, and 38% of EPCs are looking at consortia or partnerships that link up multiple EPCs with different skill sets.

Improving the economics with advanced digital technologies. The elephant in the room is the economic investment required for sustainability, and reducing what Bill Gates refers to as the "green premium."[4] Seventy-three percent of respondents feel that economics are a significant barrier to momentum in these projects. The EPCs who look at this opportunistically will see that there is a way to strongly differentiate based on going further than "designing to meet a specification." Instead, the best design teams will embrace the most advanced digital technologies, including hybrid models that incorporate artificial intelligence with rigorous design tools.

Major takeaways for EPC leaders.

Future market leaders will be those that incorporate sustainability results into all their capital project bids and execution. There are significant hurdles that largely revolve around developing the proven capability and expertise to conduct sustainability projects and reduce the future risk. However, companies across many industries and geographies are strongly committed to meaningful capital projects across various sustainability dimensions. HP

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Plastics circularity: How to solve the challenge of retaining quality in recycled polymers

Businesses and governments around the world have united behind the vision of a circular economy for plastics. Realizing this vision calls for industry-scale innovation to ensure that plastics are reusable, recyclable or compostable.

Among the many obstacles to overcome is the need to maintain high polymer quality over multiple recycling loops, which is critical to the viability of plastics recycling and to increasing the use of recyclates. Demand from brand owners for high-quality recycled polymers remains high. This is in combination with their willingness to reduce plastic waste and use it as future raw material. Therefore, enormous efforts are going into technology, process and product development to achieve these key targets.

Industry requirements. In Europe, a pledge by the European Union (EU) in 2018 revealed that 10 MMt of high-quality post-consumer resin (PCR) will be needed in 2025 to meet industry requirements. In 2018, the recycling rate globally was at 21%, with a significant share of recycled material being used in lower value applications.

Due to its quantities in the market, plastics packaging is playing a prominent role in the discussion of how to transition towards a circular economy. Many brand owners have committed to ambitious targets. For example, they are reducing their use of virgin polymers by increasing the share of recycled polymers and by designing recyclable packaging. The drivers behind these ambitions are supporting the reduction of plastics waste in the environment and mitigating carbon footprints through increased circularity.

Moving packaging towards a circular economy demands an understanding of the value chain and the impact that each step has on the polymer's quality. The steps influencing the quality of the polymer are numerous, and some are more controlled than others.

Let us first start with controlled steps. Those steps influencing the quality of the recyclate start immediately after the production of the virgin polymer. It is widely known that polyolefin resins must be stabilized with antioxidants and that acidic catalyst residues must be neutralized with an acid scavenger.[1] These acid scavengers protect the polymer during the conversion process. After potential further enhancement of the plastic item by labeling, printing and filling, the product is put into the market. It is in these steps where polymer design and composition have been optimized for packaging during the last few decades. Additive amounts have been optimized for cost effectiveness in such single use applications, balancing quality and processing efficiency and reflecting the short lifetime of the products.

Additivation is fundamental to achieving a circular economy. In a circular economy, the requirements for plastic packaging change. When polymers are recovered through mechanical recycling, additional stresses are placed on the polymer. After being collected, the plastics are grinded, extruded and converted again. For polyolefin recycling, the question that arises is: What happens during these steps with the polymer and the additives, especially the antioxidants and the acid scavengers?

While it is the industry standard to incorporate additives into virgin polymers to optimize quality and processing throughput, the polymer is only partially protected by additives during recycling. Furthermore, re-additivation is not practiced. Often, additives are even considered as an unwanted impurity that should be omitted. This has a significant implication on the product quality and processing efficiency. Proper additivation also within the so-called "second life" of the polymer must be considered and adjusted to the requirements of such recycling and subsequent conversion processes.

In addition, there are influences on plastic quality that go beyond the control of processing (e.g., if the packaging is exposed to sunlight and heat by consumers or if the plastics are exposed to contamination during their collection and sorting). This can lead to polymer destruction, crosslinking and acid formation. The implications of these uncontrolled influences on polymers must be considered and counteracted with the required additivation to maintain the processing efficiency and product quality of the resulting recyclate.

The standard industry procedure for additivation is to use a primary antioxidant (used as a heat stabilizer and typically a phenolic antioxidant) together with a secondary antioxidant—a processing stabilizer, typically phosphorous-based like a phosphite or phosphonite.

To analyze the consumption of antioxidants during the circular lifetime of a commercial high-density polyethylene

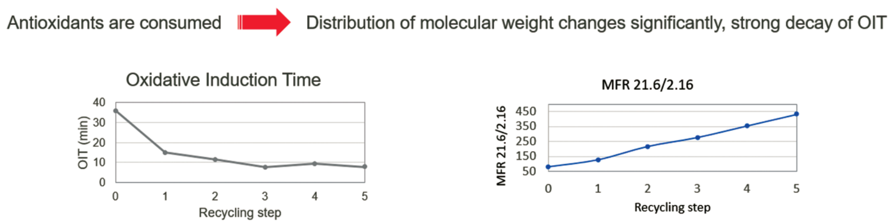

FIG. 1. HDPE blow molding grade—not enough stabilizer for circular recycling.

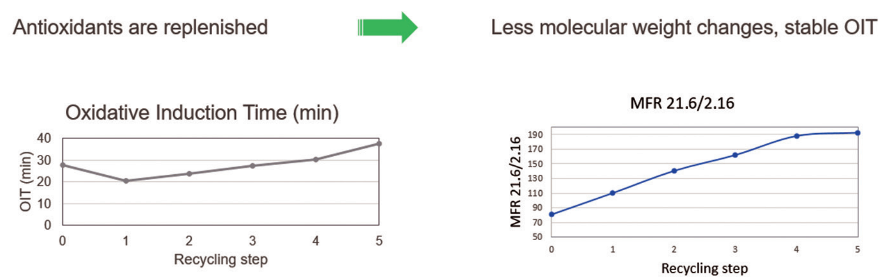

FIG. 2. HDPE blow molding grade, with the addition of antioxidants (AO 1010, PS 168 and a proprietary processing stabilizer[a]) at each recycling step.

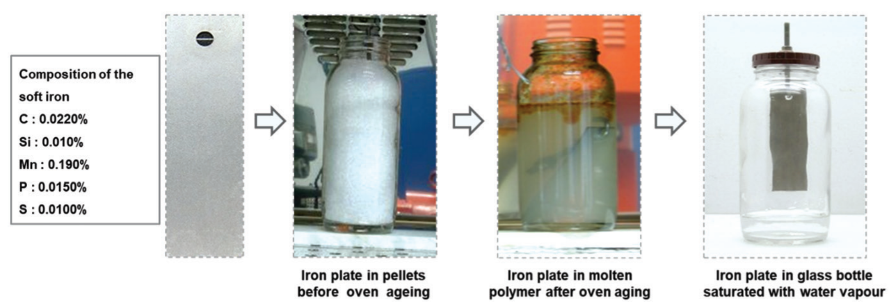

FIG. 3. Corrosion test.

(HDPE) bottle grade, five recycling steps were simulated by the authors' company.

Hanel and Roth[2] propose to use oxidative induction time (OIT) as the indicative parameter for the quality of a recycling resin. As shown in **FIG. 1,** the OIT of the HDPE resin decreases significantly from 36 min to 8 min. In parallel, the ratio of the melt flowrate (MFR) under two different loads 21.6/2.16, which is a measure for the polydispersity, increases significantly from 81 to 432. Such broadening of the molecular weight distribution in HDPE is caused by chain scission and crosslinking of the resin. The polymer structure changes significantly.

This observation suggests that the addition of antioxidants is required during recycling. **FIG. 2** shows the same resin after adding antioxidants at every recycling step. A combination of PS 168, a phosphite stabilizer, a proprietary processing stabilizer[a], a high-performance phosphonite stabilizer and AO 1010 (as phenolic antioxidant) were chosen for the simulation. Ratio and dosage were selected in a way to replenish the consumed antioxidants. Consequently, the concentration of the oxidized processing stabilizer PS 168 increases during recycling; PS 168 stays stable.

What is the impact on the polymer structure? The ratio of MFR 21.6/2.16 increases by a significantly smaller amount (i.e., from 81 to 192). This suggests an improved preservation of the original molecular weight distribution. It must be proven that this enables an easier incorporation of the recyclate into packaging production with similar processing efficiency and packaging product properties—an important step for achieving industry targets for recycled content in packaging.

In parallel, OIT even increases from 28 min to 37 min, suggesting a good heat stability of the resin even after five recycling steps. These results should be further confirmed by gel permeation chromatography and rheological measurements. It is expected that mechanical properties, such as impact strength and environmental stress cracking resistance (ESCR), worsen in cases where no antioxidants are added and are better preserved in cases where antioxidants are added.

Another observation with recycled polyolefins is an increased acidity of the recyclate. Acidity is a well-known phenomenon for virgin polymers caused by residues from the catalyst. To neutralize the acidic residues from the catalyst, an acid scavenger is added. Here, migrating acid scavengers such as zinc stearate for low-linear-density PE (LLDPE) or calcium stearate for HDPE and polypropylene (PP) is common. For example, in cases where migration is an issue for metallized film or low water carryover for raffia, the more efficient hydrotalcites are used; zinc oxide is also sometimes used for LLDPE.

Since the acidity of the catalyst after the polymerization reaction must be neutralized only once, one could presume that acid scavengers are not needed for polyolefin recycling. Nevertheless, there are several potential root causes for increasing acidity levels during recycling. These include:

1. Impurities from the packed content from foreign particles and materials in PCR. These impurities can be minimized with enhanced sorting and washing.
2. Oxidation of polyolefin, formation of aldehyde, ketone and carboxylic acid. Here, it must be expected that the tertiary carbon atom of PP is more susceptible to oxidation than the methylene group of PE. The authors have observed more corrosion issues with recycled PP than recycled PE.
3. Oxidation of the processing stabilizer to P=O and finally phosphor and phosphoric acid, although the concentration is rather low.

One way to determine the acidity of a resin is a corrosion test. Corrosion can be a severe issue for resin converters like injection molders. Rough surface molds are difficult to clean once corroded because they cannot simply be polished like a smooth mold. Corrosion on molds can lead to a coloring of the plastic item and a lowering of processing efficiency. Therefore, identifying solutions to reduce the acidity of recyclates is important to enable a scale-up of recyclate usage in the industry.

The procedure to measure corrosion is shown in **FIG. 3.** Two soft iron plates are put separately into an aluminum plate filled with a PP compound and placed in a ventilated oven at 230°C for 4 hr. After taking the soft iron plates out of the oven and removing the molten PP compound from their surfaces, the soft iron plates are hung in a tightly-closed glass bottle saturated with water vapor at room temperature for 7 d. Weights and photographs of the soft iron plates before and after testing are recorded.

FIG. 4. shows the appearance of metal plates that are non-treated, treated with recycled PP from the market, and the same recycled PP compounded with 500 ppm proprietary acid scavenger and stabilizer[b]. It becomes obvious that an acid scavenger is needed to neutralize acidic residues from recycled PP; 500 ppm of the proprietary acid scavenger and stabilizer[b] reduces corrosion significantly, but it does not eliminate it fully. Depending on the quality of the mold and the intensity of exposure during injection molding, it remains to be clarified whether 500 ppm of the proprietary acid scavenger and stabilizer[b] is sufficient in such a case to neutralize the acidic content.

The weight increase of the iron plates varies from 0.0002 without polymer exposure to polymer melt, to 0.0016 with recycled PP, to 0.0004 with recycled PP and 500 ppm of the proprietary acid scavenger and stabilizer[b]. This reflects an improvement of 75% by using this high-performance acid scavenger. Therefore, it is recommended to include additional additivation with acid scavengers at the stage of recyclate extrusion at the recycler to increase the quality of the recyclates and reduce the negative impacts on processing efficiency.

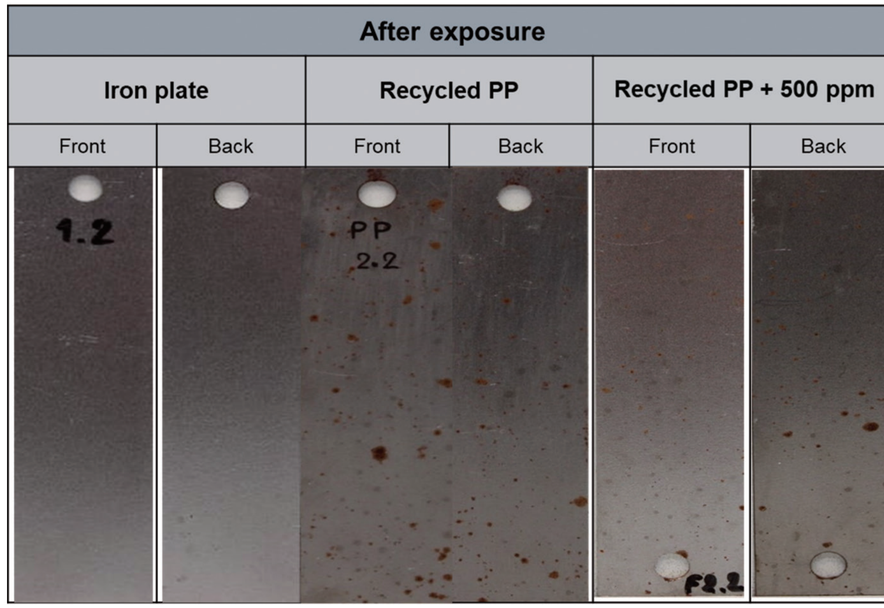

FIG. 4. Appearance of soft iron plates after exposure to saturated water vapor conditions at room temperature for 7 d.

Collaboration is a key enabler to identifying circular solutions.

Understanding the root causes for polymer quality loss along the lifecycle of the product calls for an understanding of the requirements and opportunities within several technological steps in the lifecycle. Working in and analyzing the conditions within value chain collaborations is one way forward to achieve this understanding.

Industry consortia—e.g., the EU-founded Circular Plastics Alliance (CPA), with more than 290 signatories from public and private sectors along the plastics value chain—are well placed to combine expertise and propose new ideas and solutions to overcome the obstacles to implementation. For example, the CPA recently announced a design work plan supporting the development of a guideline on design for plastics recycling.

Companies around the globe are also launching activities to foster value chain collaboration. Within the chemical industry, for example, the authors' company launched its circular plastics program EcoCircle in 2019. This program facilitates discussions with customers and players across the value chain, focusing expertise and combining product solutions with established system competences. By developing products collaboratively with customers and proving the solutions against circularity criteria along the value chain, real product solutions can be created that support the circularity of the plastics value chain. Similar programs have since been set up by other chemical companies.

Whereas this article concentrates on the impact that the implementation of correct additivation within the mechanical recycling step can have on polymer quality, it is well acknowledged that there are industry developments covering other recycling technologies such as, for example, chemical recycling. While immediate solutions are needed to make these technologies viable, the need for joint development, collaboration and an understanding of value chains remains the same, independent of the recycling technologies approached.

Product design, product composition and additivation, processing parameters and recycling technologies all must be aligned. This can be best achieved when collaborating across the value chain.

Takeaway.

This article demonstrates how additivation in the recycling process can play a crucial part in providing the required recyclate quality for achieving a circular economy. It also emphasizes that industry collaboration is a key enabler to developing new solutions and transitioning towards a circular economy.

It should be noted that from a statistical point of view, a long polymer chain is attacked with a higher probability than a short polymer chain and that it is almost impossible to reconnect polyolefin chains in a linear way once they are broken—long chain polyolefins are connected to high processability and melt stability and have good ESCR. Accordingly, the avoidance of any chain breakage while using antioxidants should be a priority within polyolefin recycling to help bring circular plastic to fruition. HP

NOTE

[a] Clariant's Hostanox® P-EPQ® powder
[b] Clariant's Hycite® 713

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Raising the alarm: Understanding the operator's perspective on refinery process alarms

As refineries and petrochemical complexes worldwide are moving toward more automated operations, plant operators are increasingly becoming dependent on process alarms for safe, smooth and continuous operation. Process alarms also play an important role in mitigating the risks during plant upsets.

During the early stages of a project, typically the front-end engineering design (FEED) stage, the client's operations team and the design engineering contractor outline the preliminary alarm requirements to assess the vital process parameters that require significant monitoring during plant operations. The definition of an alarm not only includes the proper setting of the alarm, but also consists of defining the correct priority and operator actions for the respective alarm. To confirm these parameters, an alarm management study is typically done in the engineering, procurement and construction (EPC) phase of the project. A proper study provides the operator with an appropriate action plan after an alarm has been enunciated. This plan includes steps to be taken, as alarm verification and safeguarding actions, to mitigate the possibility of any subsequent hazard.

Various design practices are followed when determining and defining process alarms for essential process parameters. The guidelines outlined in these design practices explain the steps involved in defining a process alarm. These design practices also provide the necessary documentation needed for defining the alarms, and typically vary from project to project, as defined by the client.

Once a process alarm goes off, it is the responsibility of the operator to take corrective actions in a timely manner to mitigate a potential hazard. This requires a well-coordinated effort between the panel operator and the field operator to address an alarm successfully without tripping the plant. Therefore, understanding an operator's perspective is of utmost importance while developing alarm management documents during the detailed engineering phase. It is beneficial to organize an alarm management review meeting with plant operations personnel to understand the operational and maintenance aspects of a particular process unit. Such meetings may be conducted over a few weeks, depending upon the number of alarms in that specific process unit.

The lifecycle of an alarm begins with a proper definition of the alarm. In the case of a licensed unit, this definition is provided by the licensor in the process design package. For an open art unit, the FEED package should clearly define the required alarms. Further additions or deletions of alarms typically happen during safety reviews, such as in a hazard and operability (HAZOP) analysis. Finally, all the alarms defined in the design phase are reviewed and verified for implementation in the design.

During the alarm review phase, the inputs provided by the operators are of immense importance. The operator is expected to make an assessment and to verify all alarms to ensure that the plant is operating within safe limits at all possible operating conditions. This requires the operators to participate in alarm management studies, and the outcome of these studies should be documented. The final step in the design phase is to test the alarms during the pre-commissioning stage of the project.

The following aspects are critical from an operator's standpoint during the discussion of process alarms in an alarm management review meeting.

Ownership of the process alarm. Since plant operations are run by different teams in a refinery, it is essential to define the scope of ownership for a particular process alarm. For routine flow, pressure, level and temperature alarms, ownership is usually assigned to the refinery process team, which is responsible for addressing the same. For the alarms associated with rotating equipment, along with their auxiliary systems and machine monitoring systems, ownership is assigned to the mechanical team. Interface alarms are usually the responsibility of the shift supervisor, who should consult with the unit operators and make an informed decision with the refinery leader to overcome the challenges arising out of that alarm situation.

The following example is a unique case of an alarm on a pressure transmitter. The pressure transmitter is located on the battery limit interface, and it measures the pressure of the incoming acid gas feed to the sulfur recovery units (SRUs) from the upstream amine regeneration units (ARUs). The pressure transmitter is a common instrument used for all trains of an SRU. It is equipped with high and low alarms to notify of any abnormalities in the overall system. Since the necessary and immediate modifications in operation must be done at the SRU, this alarm is owned by the SRU's operating team, so that the plant load may be varied accordingly to compensate for the fluctuations in the upstream ARU (FIG. 1).

Avoidance of nuisance alarms. During the FEED stage, the team develops the alarm documentation, considering every single possibility where process alarms are needed to monitor the behavior of a particular process unit. During the detailed engineering phase, the client's operations team may recommend that nuisance alarms be removed from the list of process alarms where they may be redundant or not significant for the operator to monitor during plant operations. A typical example would be a pressure alarm on the potable water line inside the unit. Operations typically advises that the interconnecting units should have alarms on their headers to avoid multiple monitoring within the process unit, as well. The rationalization of alarms should take place under the guidance of the client operations team and streamlined to keep only those process alarms that are vital for proper plant operation.

Prioritizing process alarms. Prioritizing a process alarm means assessing a risk associated with a process alarm and advising the operator about the magnitude of impact on plant operations—especially with respect to process safety—if the alarm goes unattended. An emphasis should be placed on defining the priority for an alarm. There can be cases where some process alarms are initially labeled as high-priority alarms, but, after a detailed analysis and discussion, the priority is lessened. The same is true for low-priority alarms that can be upgraded to high-priority levels. Too much conservatism should be avoided in defining the priorities for alarms. The number of high-priority alarms should be optimized to ensure that the operator is not overburdened in case of an emergency.

Alarms are typically categorized into high, medium and low priority, although the exact nomenclature may vary as defined by the specific design practice applicable for that project. The following example of a typical low-pressure alarm on a cooling-water main header in a process unit is used for explanation of alarm priority (**FIG. 2**). Alarm priority for a low-pressure alarm on a cooling-water header should be defined as high priority. In the event this alarm goes off, it is very important for the operator to acknowledge it and to take corrective action immediately by identifying the cause of the alarm. Low pressure would result in a low flow, leading to starvation on the cooling-water exchangers and to high temperatures inside the process units, subsequently leading to an upset of the process unit. Therefore, it is defined as a high-priority alarm that can notify the operator about the severity of the upset.

Time for the operator to act on an alarm. This is an important aspect that needs significant attention. The primary objective of a process alarm is to alert the operator about a possible deviation from the normal operating range. The alarm provides the operator a chance to take predefined corrective actions to mitigate a potential trip scenario. The emergency shutdown of a process unit can lead to production losses and negatively impact the plant life due to the sudden fluctuation in the operating conditions caused by an abrupt shutdown. Importance should be given during the design phase to ensure that sufficient response time is available for the operator should an alarm go off. Alarms with very little operator response time are seldom useful and contribute to the overall alarm count without adding much value. Consideration should be given to categorize such alarms with a lower priority.

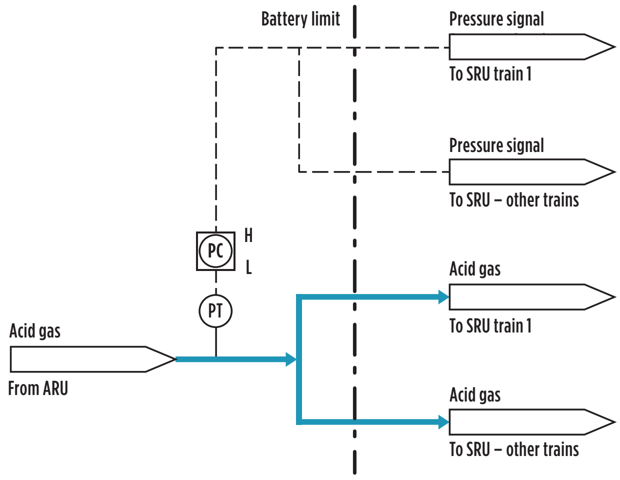

FIG. 1. Pressure alarm for acid gas to SRU.

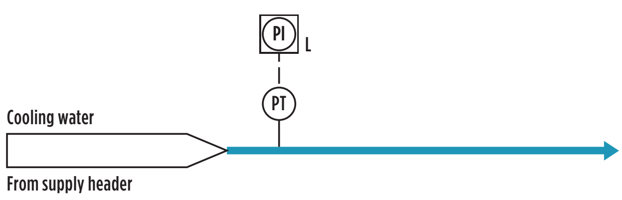

FIG. 2. Low-pressure alarm for cooling-water header.

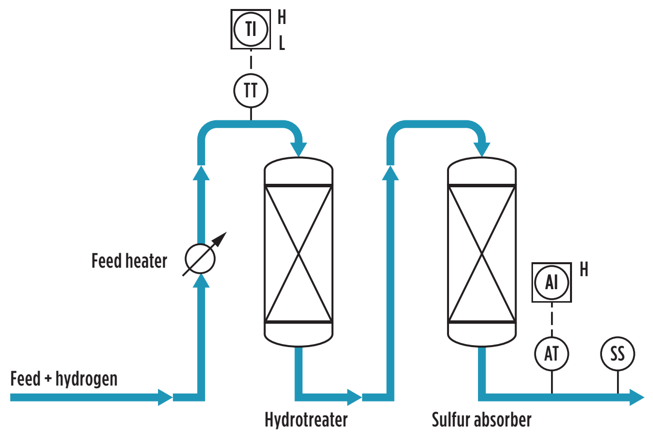

FIG. 3. Sulfur slippage from hydrodesulfurization reactors.

Mode-dependent alarms (alarms during normal operation, startup or shutdown). Mode dependency is another vital aspect to be defined during the alarm management study. The client's operations team should advise to clearly define the alarms that are mode dependent (i.e., to categorize based upon startup, shutdown and normal operation). This provides a deep insight to operators to understand the applicability of the alarm during a particular phase of operation of a process unit.

Alarm verification. It is not uncommon to have spurious alarms in a refinery. It is always useful if the alarm can be verified with the help of another independent instrument reading. It is advisable to consider a realistic alarm verification. For example, a pressure alarm in a process stream should be verified against another independent pressure instrument (such as a pressure gauge), and an indirect verification (e.g., flowrate) should be avoided. However, there may be certain instances where an indirect verification cannot be avoided. The following example from a hydrogen production unit explains the difference between a direct and an indirect verification.

The hydrodesulfurization section of a hydrogen production unit typically consists of a hydrotreater and a sulfur absorber. The mixture of the hydrocarbon feed and hydrogen is heated to the desired inlet temperature before entering the hydrotreater. The sulfur compounds present in the hydrocarbon feed are converted to hydrogen sulfide (H_2S) in the hydrotreater and are subsequently absorbed in the sulfur absorber. Inefficient operation of the hydrodesulfurization section may cause sulfur slippage, which can damage the steam reformer catalyst located downstream. For this purpose, an online analyzer with a high sulfur alarm is usually provided at the outlet of the sulfur absorber to alert the operator. A manual sampling station provided at the same location is considered a reliable direct verification for the high sulfur alarm; however, lab analysis may take some time before the results are made available. Since a low hydrotreater inlet temperature causes sulfur slippage due to poor conversion, the low-temperature alarm available at the inlet of the hydrotreater may be considered a credible indirect verification that can be verified instantly (**FIG. 3**).

Suppression of alarms. Provision for alarm suppression may be required for some alarms, such as during unit startup or equipment maintenance. Alarms with a suppression requirement should be identified and documented to make the unit operator aware of the suppression aspect of a process alarm. The automation contractor should devise a methodology to suppress alarms that will go off during a particular mode of operation. For example, in a typical process unit, when the feed is cut in, the low-level alarms will go off in most of the vessels in the unit, especially in the feed knockout drum, leading to confusion during the startup. Such alarms are suppressed until a steady-state operation is achieved. The operator can change the status of such alarms from a suppressed state to a normal state in the distributed control system once the unit is stabilized and normal liquid levels are achieved.

Clearly defined operator actions. The corrective actions to be performed by an operator in case of the activation of an alarm should be clear, specific and realistic in nature. The actions for panel operators and for field operators should be segregated and documented. If possible, actions may be outlined in a sequential manner in order of importance. The response time available for the operators is usually minimal; therefore, it is important to avoid assigning any unnecessary and irrelevant actions. Clearly defined actions provide a clear path forward for the operators, allowing them to revive the process to avoid a plant upset or trip. Obtaining a clear understanding and agreement from operators is essential.

Takeaway. Alarms play an important role in normal plant operations, as well as during startup and shutdown scenarios. Proper configuration and definition of alarms are of prime importance. A prime concept that is often neglected involves considering the inputs from the end users of these alarms, i.e., the plant operators. During the design phase for alarm configurations, it is important to consider the operators' perspectives and provide the best parameters for configuring them as defined in this article. This also ensures that the proper priorities and corrective actions are considered against each alarm. Therefore, it is important to configure alarms by taking into consideration the operators' perspectives for a safe, continuous and optimum operation of the facility. HP

NOTE

The conclusions presented in this article are solely those of the authors and cannot be ascribed to Fluor Corporation and/or any of its subsidiaries.


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High risk, high stakes: Why digitalization is critical for hydrocarbon processing

Hydrocarbon processing, by nature, is a high-risk operation. Safety is paramount, and even minor deviations in asset performance can lead to explosions, leaks, fires and environmental contamination. Highly specialized, large and expensive pieces of equipment are often single points of failure. In addition, distributed workforces have further compounded previous operational visibility hurdles. Now, teams must advance digital transformation efforts to enable real-time monitoring, improve collaboration among teams and deploy predictive tools in hydrocarbon processing plants.

Data accessibility and analysis tools are essential to an organization's ability to stay competitive, meet current challenges and optimize production outcomes. First, hydrocarbon processing plants must move beyond old, manual processes and centralize operations data into a management platform. While a data management platform collects and stores sensor-based, time-series data, these platforms are far more capable than traditional historians. Users can contextualize data, add metadata and build hierarchies to create standardized data structures and subsequent key performance indicators (KPIs). Contextualization also enables hydrocarbon processors to capture knowledge within a centralized location, ensuring that no information losses occur in the event of a staffing change.

Contextualization not only standardizes tag naming conventions, asset hierarchies and KPIs across the plant and even multiple locations, it lays the foundation for advanced tools, such as artificial intelligence- (AI-) based guidance, digital twins and visualization. Centralizing and standardizing data management eliminates manual processes and calculations, enabling teams to layer in advanced and predictive analytics for operations, maintenance and more. Once plant users have immediate access to real-time contextualized insights, they can use that information to focus on optimizing operations and production volume, and minimizing unplanned downtime.

By centralizing and contextualizing data management efforts, users from across the organization—and not just operations teams—can leverage operations data in a relevant and helpful way for their needs. For example, the process engineering team can connect operations data to a process simulation tool and run scenarios using real-time data. This enables engineers to identify equipment inefficiencies and provide direct guidance about which actions operations and maintenance teams must take to bring efficiency back into the desired range.

When hydrocarbon processing plants use the centralized platform in conjunction with mobile tools, team members can access operational data and analytics from remote locations. Previously, if an operations manager received a late-night call about an anomaly, he or she would have to drive to the plant, evaluate the situation and make a recommendation. With remote access to contextualized insights, that manager can perform an analysis from home and make recommendations over the phone. Similarly, a field worker can use a mobile app to perform root cause analysis without setting foot into a control room.

Real-time visibility and predictive analytics alert teams of current and potential asset failure and abnormal process behavior, allowing them to get the right people onsite to perform maintenance on the right parts, ensuring the asset is down for the least amount of time possible. Not only does this increase safety measures by preventing catastrophic failures, but teams can also increase uptime to ensure contractual obligations are met.

Real-world benefits. SCG Chemicals, one of Asia's largest integrated petrochemical companies, needed to increase operational visibility to boost efficiencies and minimize unplanned downtime. The company built a single platform to centralize data collection, analysis, visualization and maintenance. The platform integrates online and offline equipment data to visualize plant performance, enhance workforce efficiency and apply AI for predictive maintenance. The hybrid cloud approach provided teams real-time visibility into operations and KPIs to coordinate asset performance management and use smart analytics and the cloud to streamline operations and provide decision support.

The combination of real-time data in the digital reliability platform (DRP) and AI-driven analytics tools allows users to predict equipment health, monitor performance and make better decisions about anomalies and repairs. Users have access to actionable information in 10 sec or less from one single source of operational truth. Teams use digital twins and virtual plant operations to view equipment alarms, health status and efficiently respond to emergency conditions.

The DRP not only achieved a 9X return on investment on the project in only 6 mos, but insights from the platform enabled teams to reduce overall maintenance costs. In addition, SCG increased plant reliability from 98% to 100%. HP

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Blockchain and the downstream segment: Increasing efficiency through technology

Oil and gas companies are finding creative ways to look for solutions to new problems in the face of climate change and growing environmental awareness.[1] These creative solutions are aimed to achieve their profits and investor expectations, while reducing their impact on the environment. As organizations seek out new technologies, blockchain proves to be one that is consistently useful. The use of blockchain technology is transforming the way supply chains are audited, energy markets are designed, waste management is executed and much more.[2]

Blockchain may not appear to be the intuitive choice for most who seek to accomplish tasks associated with the downstream segment. Unless studied extensively, employing blockchains may be counterintuitive, especially with the headlines about how Bitcoin consumes more energy than a small nation.[3] Yet, it is also critical to remember that not all blockchains are crypto or related to Bitcoin. Many companies are implementing this technology internally or by building conglomerate blockchains that use far less energy than external blockchains.[4-6]

Blockchain: Why use it and what are the benefits? When discussing the specific uses for blockchain that companies are utilizing, it is important to define exactly what it is and how it is beneficial. Essentially, it is a network of decentralized systems that store a database. Blockchain as a decentralized system[7] that provides consistency and immutability, resulting in a firm foundation of trust and certainty that has the potential to revolutionize the world.[8] Therefore, if two companies were to share a blockchain with data on their mutual supply chain, they would both be confident of having the same data, unaltered in any manner.[9] The companies will have a permanent record of what has been happening in the supply chain, which they can audit confidently whenever it is needed.

Downstream segment and blockchain. There are a variety of ways that oil and gas companies use blockchain to streamline operations, increase optimization, promote environmental sustainability and reduce their carbon footprint.[10] Blockchains are adaptable to a variety of use cases for everything from compliance tracking across supply chains, managing waste, optimizing pipeline inspections, to paying environmental taxes with smart contracts.[1,2] The following are some examples of blockchain uses relevant to the downstream industry:

1. **Regulatory compliance.** Environmental compliance is one of the most stringent requirements of the oil and gas industry. It is important for companies to make sure they meet the requirements of regulatory agencies—blockchain is a prime solution for this purpose. Since everything in the supply chain is easily trackable within the company, including suppliers and distribution partners, it is no surprise that many companies find this application very beneficial.

   The European Union (EU), for example, requires companies to allow independent verification of certain environmental safety measures in energy-related facilities and make this information publicly available.[11] Such measures are easy to implement with blockchain. The companies can log that safety measures were implemented, the inspectors can record that they have been verified, and anyone with access to the public chain can confirm that these steps

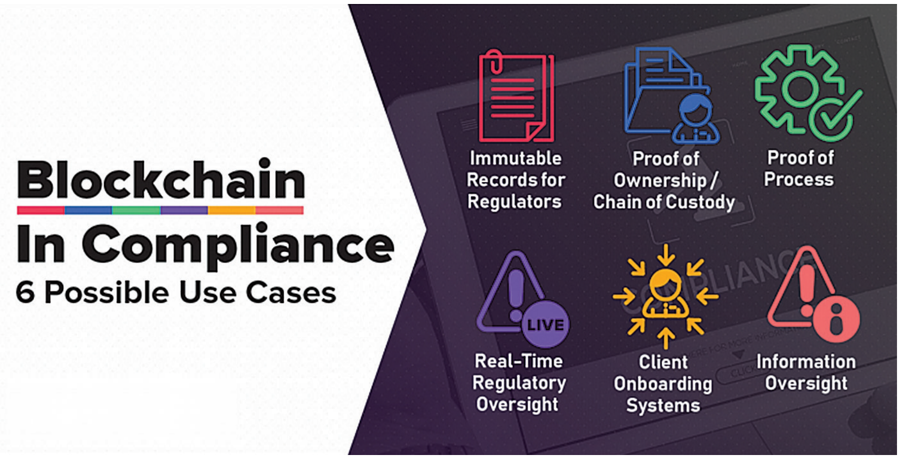

FIG. 1. Possible use cases of blockchain technology for regulatory compliance.[13]

were taken. If all these steps are taken in an immutable way, nobody can claim that the data was tampered with; if there is an error, it will be clear where the safety checks went wrong.[12,10] As a result, the environment is protected against volatile incidents, such as gas leaks and oil spills, because these regulations are strictly followed. Blockchain has multiple use cases for compliance management (**FIG. 1**).

2. **Transparency in energy markets.** Blockchain can offer an opportunity for sustainable energy beyond merely satisfying regulatory compliance requirements. The energy sector is partnering with some of the world's largest blockchain players to build platforms for bringing the energy markets to the blockchain. By creating a publicly auditable market, this initiative hopes to make the sources and practices of energy easily visible for consumers, which could lead to better purchasing decisions. The idea is to essentially incentivize companies to become greener by transparently uploading their carbon footprint to the blockchain. By doing so, they can establish a better track record of their initiatives and compare it to that of other energy counterparts.

   Blockchain technology is used in data collection, analysis, monitoring and control in the energy industry (**FIG. 2**). Rather than a proof-of-work system, like that of Bitcoin, the chain on which this market is built will utilize the more energy-efficient proof-of-stake consensus system. For instance, Shell Trading has invested in VAKT blockchain solutions, a company providing an Ethereum-based platform, and is working to implement the same blockchain technology in the trade and commodities finance sector.[14]

3. **Management of wastewater.** Another major application of blockchain is in the management of water and wastewater. Petroleum and gas production uses millions of gallons of water, and process water often contains heavy metals and other contaminants. It is imperative that this wastewater is handled carefully to prevent costly environmental damage. Blockchain can be used here to create careful records on how the waste is created, managed and disposed, which will aid in optimizing and auditing the process.[16] If waste is transported for treatment or disposal, keeping track of materials shipped and received at the other end will keep a check on errors or lapses. An open blockchain database allows for easy identification, auditing and fixing of problems. As a result, it is much better for the environment.

4. **Expedited reconciliation.** Oil and gas firms conduct more than a million transactions every day, with frequent cycles of buying and selling. Inefficiency, human error, accounting and other archaic administrative procedures can undermine the efficiency and effectiveness of these transactions. A major advantage of blockchain is its ability to support smart contracts. Contracts of this kind self-execute the tasks when certain conditions (such as quality and quantity of fuel) are met and automate the payment and collection processes between counterparties, without the need for an intermediary.[1,2,12] These payments are usually instantaneous, thus reducing cost, lag time, errors and liability. A physical verification process is presently used to reconcile all business transactions. Using blockchain technology, all these transactions can be reconciled

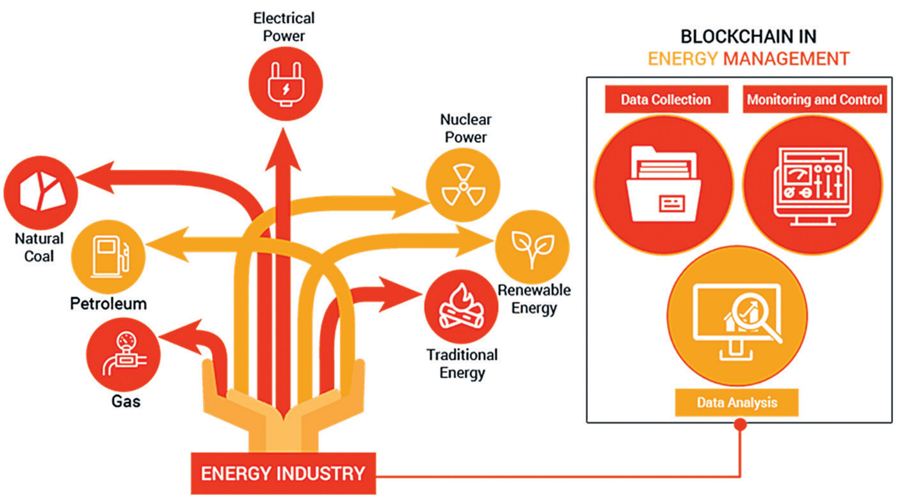

FIG. 2. Energy markets can utilize blockchain for data analysis, monitoring and control.[15]

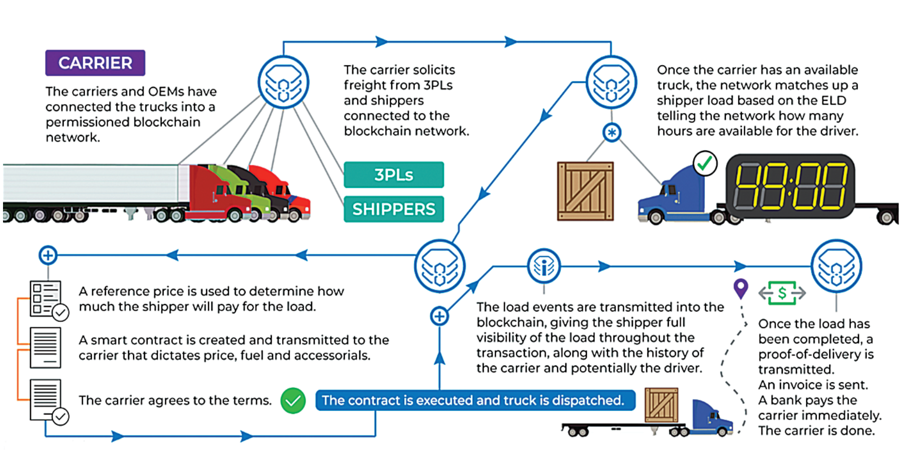

FIG. 3. Smart contracts deployed on blockchains can assist in supply chain operations.[19]

instantly and automatically through smart contracts.

5. **Transportation.** Trains or other land transportation are often used to deliver refined products from refineries to their distribution networks. Keeping track of the complex network is very difficult and errors are often introduced because of siloed data, archaic data management systems and reliance on paper transactions. New blockchain-based platforms make it possible to significantly reduce the concerns of supply chain operations.[17] The use of Internet of Things (IoT) sensors that measure temperature, humidity, volume, etc., can virtually eliminate volume losses in products and transmit the information to the blockchain platform so that the product integrity is maintained from start to finish. In conjunction with this, smart contracts can be used, and payments can be released once the products have reached their specified destinations, eliminating the need for additional administrative steps.[18] Smart contracts deployed on blockchain technology can assist in transportation and logistics to speed up supply chain operations (**FIG. 3**).
6. **Data management.** There are a lot of moving parts in the downstream sector, which encompasses everything from the refinement of products to distributing them. Companies have trouble in managing their data, as it is often incomplete and manual work is needed to complete the process, which automatically leads to errors. Despite a central database that only a few players in the field are using, there are security and other permission concerns, as evidenced by the recent ransomware attack on Colonial Pipeline.[20] Blockchain technology provides easy access to all relevant business data, as well as transparency and security through its secure, distributed ledger.[21] Smart contracts can ensure that data is shared with other parties only when necessary and are less likely to be attacked by hackers due to their integration and permissions.[12]

   Abu Dhabi National Oil Co. (ADNOC) teamed up with IBM to create a blockchain-based platform that tracks and records both the quantities and financial values of each of its operating companies' bilateral transactions, streamlining its accounting process as part of its smart growth strategy.[6] Blockchain solutions can enhance the efficiency of data management by automatically logging all data at each stage (**FIG. 4**).

Challenges. Blockchain technology is still a challenging technology to implement in the oil and gas sector despite its many merits. Challenges include:

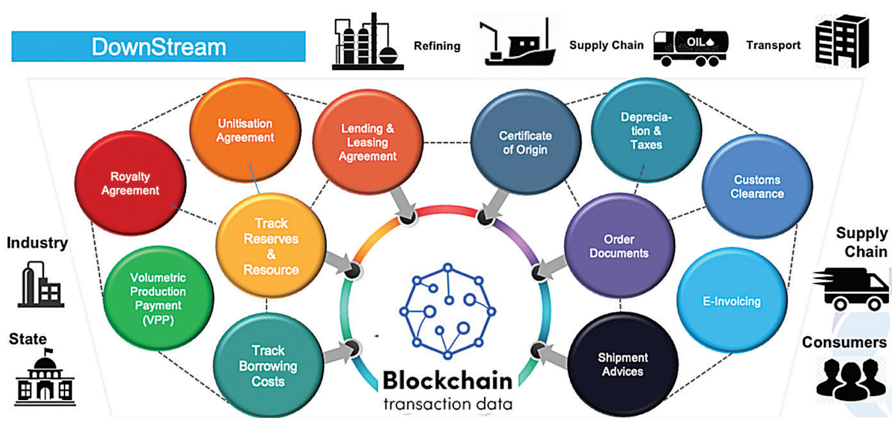

FIG. 4. Data management made efficient for downstream processes using blockchain technology.[22]

- **Newer technology:** A newer technology may be inconvenient for some people since they have become comfortable with their legacy systems. In this sense, the change will have to be gradual and implemented over time.[23]
- **Scalability:** To record millions of transactions daily, it will take massive infrastructure, which comes at a cost. Companies may not be willing to invest in a relatively new technology that has few use cases.[23,24]
- **Regulation:** Blockchain technology has received a lot of attention from governments around the world as a form of innovation that has the potential to pave the way for future developments. However, no official rules or regulations have been established for the technology. [24] Several U.S. states (e.g., Colorado, Ohio and Wyoming) are slowly beginning to open their markets to this technology.[25]
- **Security:** Since there are not enough use cases to exploit, there is a possibility of an unexpected security loop. [23] As a result, it would take some time and effort to test out the system and remove any security threats the organization might face.[24]

Takeaway. In this evolving industry, efforts are continually made to improve processes and to take environmental considerations into account in the best way possible. Blockchain technology is proving to be an invaluable tool in this regard, as it builds compliance, transparency and allows easy auditing to demonstrate increased efficiency. Companies will benefit from increased insight regarding their supply chains and potential problems and will be able to optimize their processes to be as environmentally friendly as possible. HP

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Expect the unexpected: Estimation of uncertainty in custody measurement

Uncertainty in input parameters does not have an identical effect on uncertainty in the output. The uncertainty estimation process here reveals this phenomenon with multiple unexpected findings that help to take appropriate mitigative measures to reduce the estimated uncertainty in the output. This paper discusses these unexpected revelations during uncertainty estimation in custody metering systems.

When any measurement is made, its outcome depends on the measurement procedures, accuracy of instruments, human and environmental factors, etc. Due to these factors, repeated measurements do not agree with one another, but tend to disperse in a certain band. Any repetition of the measurement will produce a new result that is expected to lie within this band.

The spread of the measurement results is a sign of the quality of measurement. Their average provides an estimate of the measurement value that is more reliable than an individual measurement. The average of the measured values is not necessarily the true value due to unknown systematic errors. It is impossible to state how well the unique true value of the measurand (the quantity whose value we want to evaluate) is known, but only how well it is believed to be known; therefore, any measurement result is considered and quantified in terms of probability that expresses degrees of belief.

The uncertainty in a measurement reflects the lack of exact knowledge of the value of the measurand. The result of a measurement after correction for known systematic effects is still only an estimated value due to the potential for random errors and from imperfect corrections of systematic errors.

Uncertainty is defined as a parameter associated with the result of a measurement that characterizes the dispersion of the values that could be attributed to the measurand. For example, the parameter may be a standard deviation, absolute value or percentage of measurand, along with the level of confidence. Uncertainty defines a statistical interval around the measured value within which true value is expected to lie.

Measurement essentials are illustrated in **FIG. 1.** The true value of measurand is shown in the thick green line. The small red lines, indicative of the value of measurement at repeated attempts, are spread within a certain band. The average value of repeated measurement is indicated by the blue line. The difference between the true value and the measurement average value is the error in the measurement. The design and operation engineering objective of a metering system is to reduce the spread of estimated uncertainty to as small as possible. The result of a measurement can unknowingly be close to the true value of the measurand and, therefore, have a negligible error even though it may have a large uncertainty.[1,2]

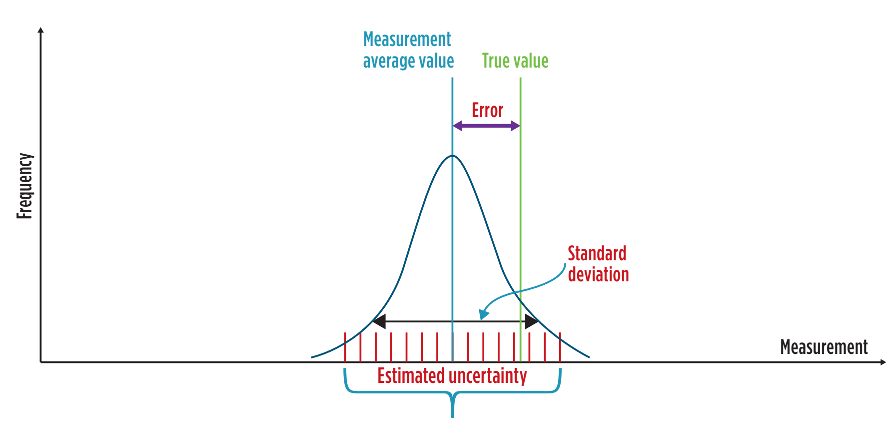

FIG. 1. Measurement essentials.

UNCERTAINTY ESTIMATION IN A CUSTODY METERING SYSTEM

The primary purpose of a custody/fiscal metering system is to determine the quality and quantity of commodity transferred. Most measurement systems differ due to variances in manufacturers and types of instruments used. Additionally, the environmental conditions where

the metering systems are installed and the parameters associated with metering system operation contribute to measurement uncertainty. Uncertainty analysis of a metering system should be performed during the detail design stage to understand the estimated uncertainly in the flow measurement. If the estimated uncertainty is beyond the acceptable limit, suitable actions like design changes, instrument selection, testing, etc., can be undertaken.

Stages of uncertainty estimation. Uncertainty estimation is performed in the following stages:

- **Formulation**—defining the output quantity; identifying the input quantities using the calculated output; developing a measurement model relating output to the input quantities; identifying elemental error sources in each input quantity; and assigning probability distributions to the input quantities.
- **Propagation**—deriving the effect of unit change in the input on the output (or sensitivity co-efficient) using a numeric method, analytic method or Monte Carlo method.
- **Summation**—determining combined standard uncertainty; determining expanded uncertainty; and reporting the result of estimated uncertainty in the output.

Approach in estimating uncertainty. Generally, fluid volume at standard conditions is calculated from the indicated volume—corrected for meter factors, volume correction factors or gas compressibility—to account for the effect of temperature and pressure on the fluid.

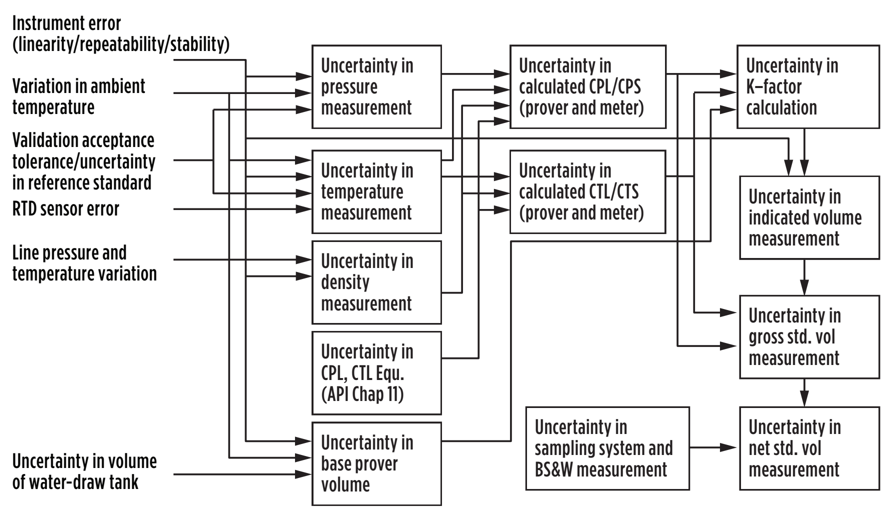

FIG. 2. A generic multistage measurement model of a liquid hydrocarbon measurement process.

Parameters like pressure, temperature, volume flow at line condition, quality parameters like gas composition or density, etc., are measured continuously to derive standard volume/mass flowrate. The uncertainty in the measurement of these parameters will propagate as uncertainty in the calculation of the standard volume of fluid.

To simplify the uncertainty estimation, a multistage model of the measurement process should be developed where the output quantity from previous stages becomes the input quantity to subsequent stages. This model helps to identify the major contributors at each stage of measurement. It also helps in simplifying the uncertainty estimate and avoids gross mistakes.

A generic multistage measurement model of a liquid hydrocarbon measurement process is provided in **FIG. 2.** Dividing the measurement process into small blocks would be useful to understand the effects and propagation of uncertainty of each contributor.

Sources of uncertainty. In practice, measurements of input parameters have many potential sources of uncertainty, including:

1. Environmental conditions of the measurement
2. Process operating conditions
3. Uncertainty in measurement standards, reference materials, constants, etc.
4. Approximations and assumptions in measurement methods and procedures

TABLE 1. A pressure measurement uncertainty budget table

Sr. No.	Symbol	Source of uncertainty	Input uncertainty	Relative uncertainty, %	Probability distribution	Divisor	Standard uncertainty, %	Sensitivity co-efficient	Contribution to overall uncertainty
A	B	C	D	E	F	G	H = E/G	I	J = (H × G)^2
1	$e_{PATamb=}$	Ambient temperature effect	2.3745	0.3%	Normal	2	0.148%	1	0.00022%
2	$e_{Pacc=}$	Instrument error class	0.44	0.06%	Normal	2	0.028%	1	0.00001%
3	$e_{Pstab3=}$	Instrument stability	0.036	0%	Rectangular	1.732	0.003%	1	0%
4	$e_{Pcal\,=}$	Calibration instrument	0.5	0.06%	Rectangular	1.732	0.036%	1	0.00001%
5	$e_{Pchk=}$	Loop check tolerance	1	0.13%	Rectangular	1.732	0.072%	1	0.00005%
		(Combined Uncer)^2							0.00029%
		Combined uncertainty							0.17117%
		Expanded uncertainty			Normal	2			0.34233%

5. Incorrect installation and errors in instruments
6. Nonrepresentative sampling
7. Operator skill, human factors, etc.

An unrecognized systematic error cannot be considered in the evaluation of measurement uncertainty, but it can contribute to measurement error. The skill lies in identifying all potential contributors to measurement uncertainty for the given application. The associated uncertainty of an input parameter is estimated based on experience and all available information on the possible variations in the input parameter.

Uncertainty budget. The uncertainty budget data is prepared and populated in a spreadsheet for each measurement block. This budget helps to identify the biggest contributors to the uncertainty in the final output, and is very useful in directing uncertainty reduction efforts. **TABLE 1** is a typical example of an uncertainty budget for pressure measurement.

The factor that is < 20% of the largest value in column H contributes < 4% of the final value; these sources of uncertainty may require comparatively less attention when attempting to reduce overall measurement uncertainty.

ESTIMATING UNCERTAINTY—EXPECT THE UNEXPECTED

The uncertainty in input parameters does not have an identical effect on the uncertainty in the output parameter due to the varying sensitivity coefficients for each input. Input parameters with a high sensitivity coefficient have a higher impact on the estimated uncertainty in the output compared to an input with a lower sensitivity coefficient. The uncertainty estimation process (as explained previously) would reveal this phenomenon and can lead to multiple unexpected findings. These findings would help operators to take appropriate mitigative measures to reduce the estimated output uncertainty.

Effect of ambient temperature on field transmitters. Operating pressure values are required to calculate the volume of gas or liquid hydrocarbon at standard or base conditions. High-accuracy transmitters are normally selected to present lower uncertainty in pressure measurements. However, scrutiny of the pressure measurement uncertainty budget table may reveal that variations in ambient temperatures—in which the pressure transmitter is located—are one of the biggest contributing factors to pressure measurement uncertainty.

For a typical application where the difference in the ambient temperature between the transmitter calibration and actual operation is 15°C, the additional uncertainty of ~0.30% is found in the pressure measurement, which is five times higher than the reference accuracy (0.06%) of the transmitter. As the difference in ambient temperature increases, uncertainty in the pressure measurement increases. Refer to the typical budget in **TABLE 1** for visual reference.

Pressure transmitters that perform better even for a wider variation in ambient temperature should be used to reduce uncertainty in the pressure measurement and flow measurement. Additionally, to

reduce adverse effects due to sun radiation or extreme cold, pressure transmitters may be provided with sunshades, or installed in an enclosure with vortex coolers or enclosures with space heaters, as applicable and suitable for each particular installation.

An uncertainty estimation may reveal major, and often unexpected, contributors to the estimated uncertainty. A system designer may use these revelations to take appropriate mitigative actions to reduce uncertainty in the overall measurement.

Effect of RTD accuracy in temperature measurement. Accurate measurement of operating temperature is required to calculate the volume of fluid, particularly liquid, at standard or base condition. The analysis of the temperature measurement uncertainty budget table may reveal an accuracy tolerance of a resistance temperature detector (RTD) as one of the biggest contributing factors in temperature measurement uncertainty. The RTD Type B normally used in the industry has an accuracy of tolerance of 0.3°C; the RTD Type A has an accuracy tolerance of 0.15°C.

To reduce the effect of RTD element uncertainty in the overall temperature measurement uncertainty, each RTD element may be calibrated and the specific values for the Callendar-Van Dusen constants for that RTD sensor may be used in the temperature transmitter.

Effect of loop validation acceptance tolerance. Primary and secondary measurement devices used in custody measurement are regularly validated against reference standards of the lowest possible uncertainty. Company standards normally specify the acceptance difference between the reference standard and field transmitter before an adjustment of the field transmitter is performed. The field transmitter is adjusted if the output is outside the acceptance tolerance.

Operating companies typically allow 0.5°F of tolerance between the field transmitter and the certified reference thermometer before the field transmitter is adjusted. However, an uncertainty budget for the temperature measurement may reveal that the acceptance tolerance in transmitter calibration can be one of the biggest uncertainty sources in the temperature measurement.

To mitigate this source of uncertainty, the reference instruments of least uncertainty and least possible loop acceptance tolerance may be used. Also, to avoid the creeping in uncertainty due to analogue signal conversions and loop acceptance tolerance, a digital signal may be employed for secondary instruments.

Effect of uncertainty in density measurement. Product density requires a calculation of the volume of the liquid from operating condition to the volume of liquid at standard condition of 15°C (60°F) at atmospheric pressure. Though the value of density is an important parameter in the calculation, the accuracy of the density measurement can be (unexpectedly) not as important in the overall uncertainty in the standard volume. For a typical crude oil custody metering application, a ±0.5% uncertainty in the operating density measurement (±0.5 kg/m^3) may result in a ±0.04% uncertainty in CTL. The normal process density meter may be sufficient for the application need, as uncertainty in CTL would be further eclipsed by uncertainty in gross volume.

Effect of meter runs in parallel. Custody metering systems normally consist of multiple flowmeters in parallel meter runs. The common notion is that the higher the number of meters runs, the higher the uncertainty. However, due to the non-correlations effect of various measurements in parallel meter runs, the overall measurement uncertainty in a multiple meter run system tends to be lower than a single meter run measurement.

Effect of dimension measurement. The meter tube internal diameter (ID) and orifice plate bore diameter are important parameters to calculate flowrate using an orifice meter. An uncertainty of 1% in meter tube ID measurement can result in a 0.5% uncertainty in flowrate. However, the same level of uncertainty (1%) in an orifice bore ID measurement can result in a significant 2.5% uncertainty in the flowrate. Uncertainty in orifice bore ID has a higher impact on the uncertainty in the flowrate, as the sensitivity coefficient is higher compared to low sensitivity coefficient for meter tube ID measurement.

Takeaway. The evaluation of uncertainty depends on detailed knowledge of the measurement application. The quality of the uncertainty estimation therefore depends on the assessor's knowledge, understanding and critical analysis abilities. Any uncertainty estimation process provides insight into the impact of each input on the output, and provides tools to identify its importance. This helps users to take appropriate mitigative measures to reduce overall uncertainty in the output. Reductions in uncertainty depend on the practical feasibility and commercial viability on implementation. HP

NOTES

The suggestions and guidelines provided in this article should be considered general in nature and not authoritative and final.

REFERENCES

1. International Organization for Standardization (ISO) 5168, "Measurement of fluid flow—Procedures for the evaluation of uncertainties," 2005.
2. Joint Committee for Guides in Metrology (JCGM) 200, "International vocabulary of metrology—Basic and general concepts and associated terms," 2012.

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Accelerating and expanding process control benefits

Advanced industrial data analytics has a prominent role to play in process control and automation. The success of process control and automation efforts depends on the skilled design and automation of process behavior understanding. Advanced analytics applications enable the integration of this process understanding with process- and equipment-related relationships, which can be gleaned from historical process data by subject matter experts (SMEs) using advanced analytics.

Therefore, it is the combination of process knowledge, engineering skill, advanced analytics and information-rich process data that yields control and automation implementation improvements in the form of variability reductions, production increases, reduced energy and waste, and other operational improvements.

As control engineers well know, analytics scope can extend from the micro scale (individual controllers) to the macro scale, where unit or plantwide control strategies may involve many proportional-integral-derivative (PID) controllers, as well as advanced process control and real-time optimization layers (**FIG. 1**).

Well-designed advanced analytics tools can efficiently focus on the process data anywhere along this wide range of scale, whether the engineer is fitting a dynamic model to retune a single PID controller or monitoring the constraint status of a large-scale advanced process control implementation. When it comes to process control analytics, this type of scalability and flexibility is essential.

Industrial data challenges. To earn its prominent role in control and automation, advanced analytics must address many real-world data challenges. Failure to provide the needed features exponentially increases analysis time and leaves valuable insights undiscovered. The features must be designed well, with appropriate visual aids, to allow the SME to rapidly iterate through analyses.

Features needed in control and automation analytics include:

- **Data connectivity:** The analytics application should connect to all needed sources of data to seamlessly integrate data from different sources into trends and calculations.
- **Data cleansing:** Cleansing is an essential first step. It includes smoothing, outlier removal, excluding downtime and aligning data.
- **Contextualization:** The second step is contextualization—finding specific time periods of interest (e.g., startups, product transitions, a certain production mode, or batch step). This focuses the analysis to only the data appropriate for the objectives.
- **Analytics flexibility:** Tools and visualizations must encompass the broad categories of analytics: descriptive, diagnostic, monitoring, prescriptive and predictive. Tools should also be extensible to the more specialized needs of control engineers, such as dynamic modeling, digital filtering, cross-correlation heatmaps, causality and controller performance.
- **Asset structures:** Analytics must seamlessly integrate with asset data structuring and include associated calculation scaling features.
- **Comprehensive and collaborative analytics:** The analytics application offers the full range of analytics tools, methods and visualizations needed to bring together the various manufacturing roles.

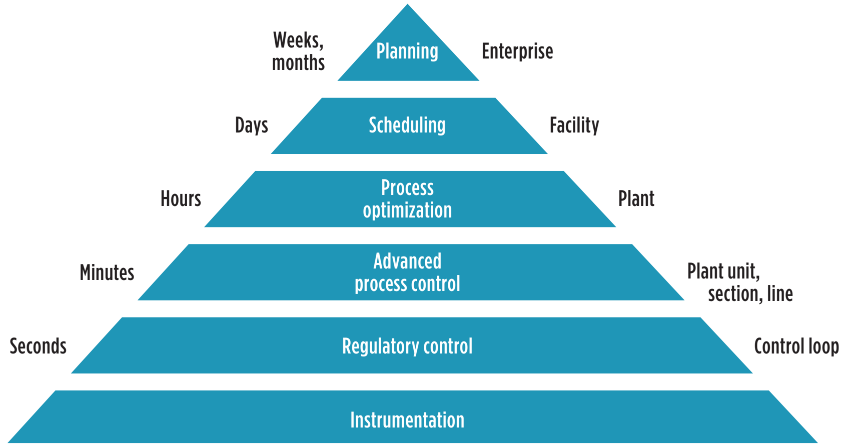

FIG. 1. Process control and automation hierarchy.

Fully featured analytics addresses issues. Whether troubleshooting process control performance or analyzing process control improvement benefits, control engineers often want to find recurring, specific time periods of operation (e.g., start-ups, transitions, phases, setpoint ramps and batch sequences), and then perform analyses on those time periods.

To perform these and other related activities, an advanced analytics application provides extensive contextualization tools, with the resulting contextualized time periods referred to as capsules and conditions. Capsules are individual time periods of interest, such as "Steam Control Valve Open," making up an overall condition containing the individual capsules across time. These contextualization tools are specifically designed for creating insights to process data and provide many identification methods, including threshold deviations, increasing/decreasing trends, time spans pre- and post-events, and others. These types of contextualization tools are critical for gaining process control insights from raw, historized data.

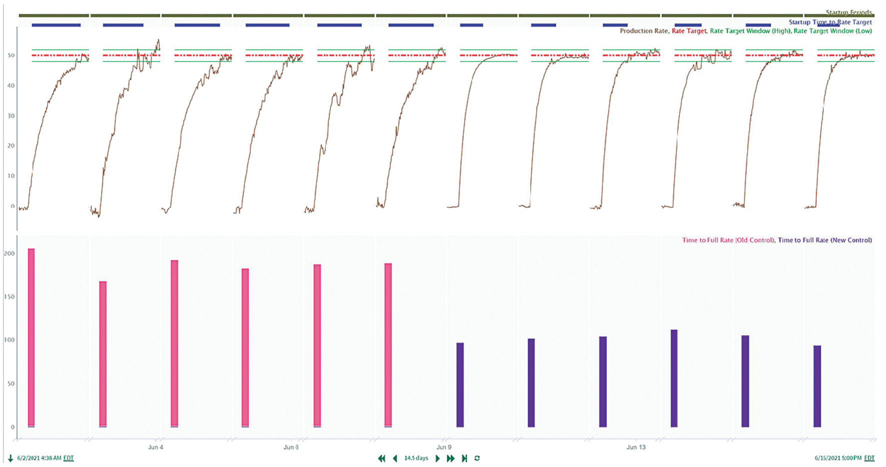

FIG. 2. Chain view shows automatic control improvements have decreased time to reach steady-state operation at target production rates.

FIG. 3. Control valve health monitoring treemap enabled by asset features (A). Clicking on the LIC109 valve asset in the treemap enables quick access to the underlying data (B).

Moving into the reporting arena, advanced analytics applications provide users with the ability to publish their calculations into auto-updating reports and dashboards, establishing a common platform for a range of reporting and workflow management applications, such as daily production meetings, incident investigation summaries, live control room displays and other collaborative activities. This type of common platform brings other organizational roles into the analyses (e.g., management, process engineers and maintenance), promoting collaboration with control engineers by streamlining information sharing.

Where applicable, asset trees residing in asset-configured data sources or created by advanced analytics tools can rapidly extend analyses and reports across similar assets, such as controllers, pumps, production lines or even sites. The calculations can be built once by the user and then applied across many assets.

Whether built-in to the core analytics tools or made available via coding extensibility features, methods specific to process control are fully integrated within the analytics application. For example, when doing control strategy design or controller tuning calculations, control engineers often need dynamic model fitting capabilities to handle the time lagged responses common to industrial processes. Standard linear regression prediction modeling falls short, but the right advanced analytics application will have more advanced options to solve these types of problems.

Accelerating insights and benefits: Four use cases. The value of advanced analytics for process control and auto-

mation is illustrated with the following four use cases.

Use Case 1: Quantifying automatic control improvements. Comparing process performance metrics before and after automatic control modifications is a common analytics task for control engineers. In this use case (**FIG. 2**), additional profits can be attained if the target production rate can be reached more quickly following startup, with a new control strategy implemented to reach this goal.

Beginning with only the production rate signal and the rate target, the control engineer searches the data to identify when the production is within a narrow range of target, and then uses additional contextualization functionality to join the beginning of startup to when the rate target is reached, creating "Startup Time to Rate Target" capsule periods.

The startup related control performance is then trended over each of the most recent 12 runs in the analytics application's chain view, which contextually excludes all run data not of interest. The "Time to Full Rate" for the old and new control strategies is then quantified and compared, and results show the time has decreased from 150 min–200 min to approximately 100 min. Utilizing analytics and process knowledge, the control engineer has rapidly quantified the before/after performance for a new control strategy implementation.

Use Case 2: Leveraging asset features for control valve health monitoring. Advanced analytics solutions take advantage of asset-organized data structures to efficiently scale calculations across all assets. Features within the analytics solution apply the calculations—created only once by the user—to all similar assets (pumps, control valves, etc.). Results can be viewed in high-level visualizations like treemaps, with interactive drill-down functionality to access the individual asset's underlying process data. Results can also be changed on the fly to view how a particular asset is currently operating.

This functionality provides the desired wide range of analytics scaling because results can be developed from the micro (individual assets) to the macro level (entire process sections). The ability to view results at various levels promotes collaboration among organizational roles, as well as the involvement of management. Management reviews can establish priority and generate workflow actions for engineers and maintenance personnel to address issues.

In this example, a control valve asset tree contains analogous signals (e.g., valve output) related to each control valve. The control engineer uses analytics tools to create an overall valve health score based on calculated metrics, such as percent traveled, rate of travel, cycling and other parameters. Red assets in the generated treemap (**FIG. 3A**) alert the users to poor control valve health. Clicking on the asset in the treemap shows the related data trends (**FIG. 3B**).

Use Case 3: Monitoring operator interactions with the regulatory control layer. While occasional operator intervention is necessary, in some cases, operators do not trust the control strategy, and they unnecessarily place controllers in manual mode; or, they simply think they can improve operations by being the feedback controller for their shift,

Advanced industrial data analytics has a prominent role to play in process control and automation. The success of process control and automation efforts depends on the skilled design and automation of process behavior understanding.

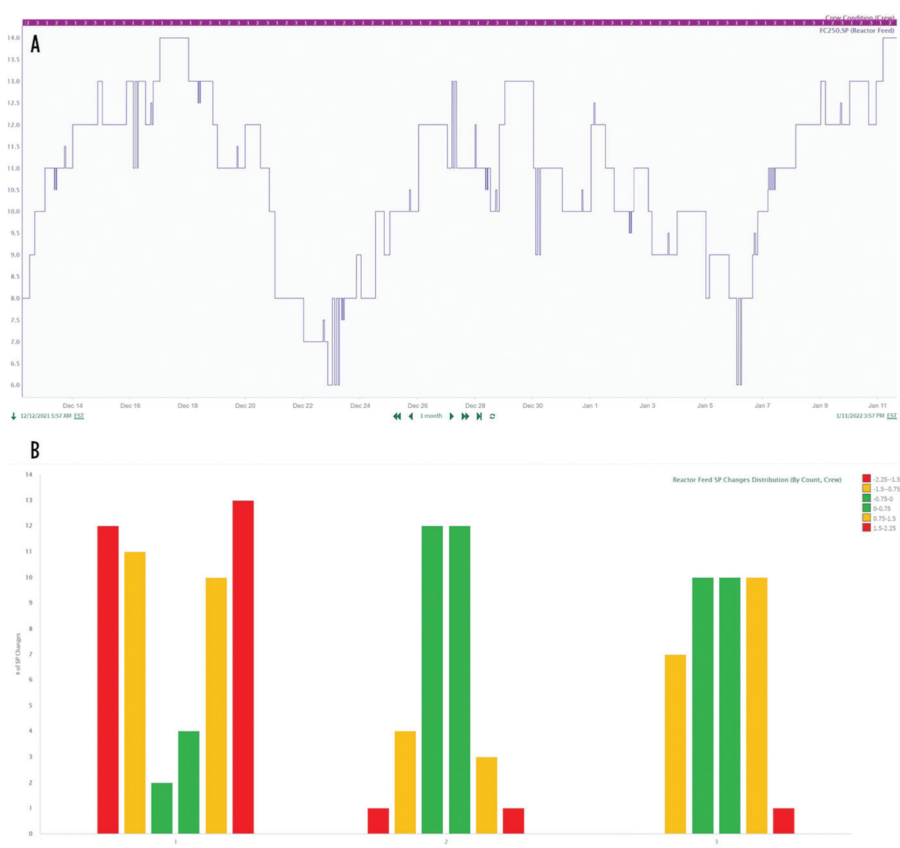

FIG. 4. Reactor feed controller setpoint adjusted by operators to loosely control process inventory (A). Histogram of reactor feed controller setpoint change magnitude by crew number (B).

and they often end up overcontrolling by making too frequent or excessively large adjustments. As a result, regulatory control strategies underperform, not only due to tuning or design flaws, but due to operator acceptance. Monitoring this type of operator behavior can reveal improvement opportunities.

For the first part of this use case, the control engineer is concerned about variability in a reactor feed flow controller setpoint that operators adjust to manage process inventory. Reactor operation is extremely sensitive to feed changes. Operators have been trained to make infrequent adjustments no larger than 0.5 units, and the inventory does not need to be tightly controlled. Starting with only the reactor feed setpoint signal (**FIG. 4A**), the control engineer excludes downtime periods, calculates sample-to-sample changes and creates time capsules for Crew 1/2/3 operating shifts.

A histogram (**FIG. 4B**) is generated showing the distribution of setpoint changes by number (y-axis) and crew (x-axis), with yellow/red bars flagging undesirable large changes. The analysis reveals Crew 2 is performing the best (lowest number of changes, highest green bars). Crew 1 behavior is the cause of the undesired reactor variation, evidenced by the high yellow and red bars. Action is then taken to learn from Crew 2's behavior and improve Crew 1's approach.

For the second part of this use case, the control engineer starts with Crew 1/2/3 shift capsules, and controller mode signal data (0=manual, 1=automatic, 2=cascade) in an asset data structure for the 21 controllers comprising Unit 1 of the process. Downtime data is removed and the weekly percent time in manual is set up as a crew-specific calculation scaled to each controller (asset).

Value searches identify when the weekly percent time in manual is greater than 15% and greater than 50% to flag underutilized controllers. Crew behavior is displayed in an asset-enabled treemap (**FIG. 5**), where each Unit 1 controller is represented by a green, yellow (manual > 15% of time) or red (manual > 50% of time) square.

FIG. 5. Crew 1: Unit 1 controllers percent time in manual mode, greater than 50% in red (A). Crew 2: Unit 1 controllers percent time in manual mode, greater than 50% in red (B). Crew 3: Unit 1 controllers percentage time in manual mode (> 15% yellow, > 50% red). Crew 3 is underutilizing TC109 and PC117.

Unlike Crews 1 and 2, Crew 3 is running TC109 in automatic mode less than 50% of the time. TC109 is a recently-commissioned controller designed to reduce product quality variability. Action is taken to further train Crew 3 on the importance of keeping this controller in automatic.

FC157 and TC119 are controllers that all crews leave in manual. Crew feedback reveals the associated control valves need resizing to avoid saturation issues, so maintenance is scheduled.

Crew 3 is running PC117 in manual mode between 15% and 50% of the time, resulting in its yellow designation. Conversations with Crew 3 reveal PC117 always oscillates following an equipment procedure only scheduled during their shift. An action item is given so the control engineer can address this oscillatory behavior.

This two-part use case shows how advanced analytics can efficiently focus calculations from the micro to the macro level, depending on the control engineer's objectives. Starting from historian data, actionable results were generated for both a single controller setpoint change analysis and for unit-wide controller mode monitoring.

Use Case 4: Diagnosing cause and effect to find the needle in the haystack. Poor performance is sometimes isolated to single controllers, and the need for retuning or valve maintenance can be quickly determined. In more complex situations, poor performance is widespread, with a single problem propagating across many controllers. Before the problem can be addressed, the controller—which is the root cause of the variability—must be identified.

Root cause identification can be tedious, particularly in processes with recycle streams, heat integration and features that mask cause and effect relationships. Causality algorithms mathematically quantify cause and effect relationships among signals, revealing relationships obscured on time series trends. Without analytics to guide troubleshooting and narrow the potential root causes, control engineers may spend many hours performing invasive process tests and inspecting data trends.

In this use case, a plant-wide oscillation lasting for about 2 hr persists through the measurements and controllers designated with blue and red circles (**FIG. 6**). The dataset of oscillating controller process variables (**FIG. 7**) is input to the causality analysis. The directional arrows in the generated causal map (**FIG. 8**) guide the engineer toward controller LC2 causing the related oscillations in TC1 and TC2. Combining the causality results with process dynamics and connectivity knowledge, the engineer agrees that LC2 is a suitable candidate for the root cause and confirms this with additional plant testing. Complementing analytics tools for monitoring, diagnostic tools like causality can streamline tedious investigations, enabling the full range of control workflows.

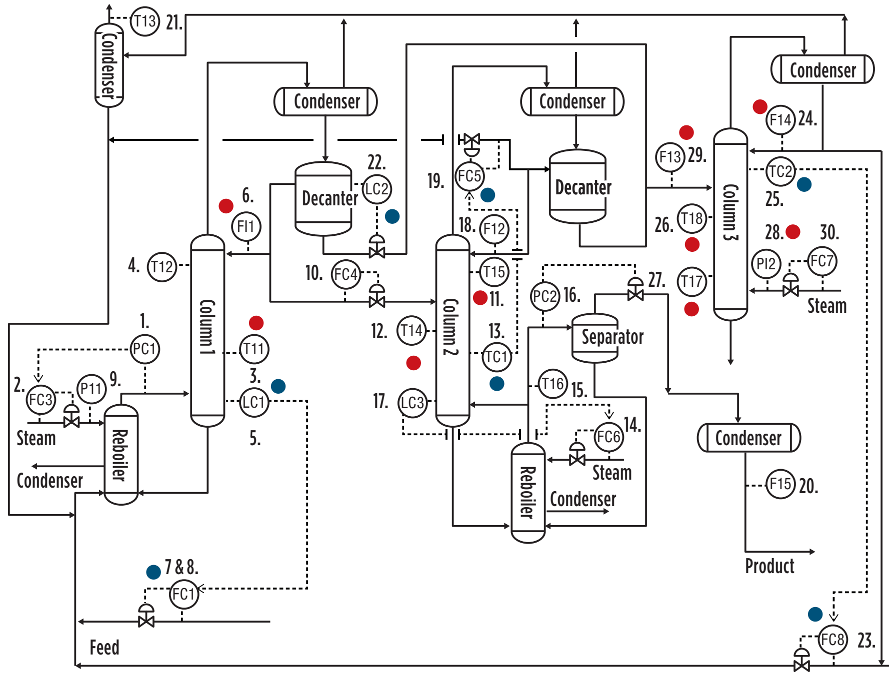

FIG. 6. Chemical process exhibiting plant-wide oscillations. Red circles designate cycling measurements and blue circles designate cycling controllers.

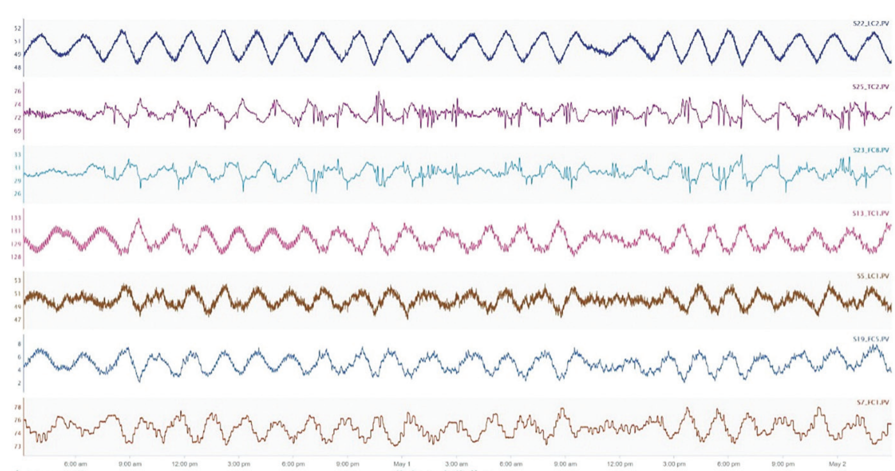

FIG. 7. Oscillating controller data over a 2-d period. With all controllers cycling at a similar frequency, the oscillation source is not readily apparent.

Good things come in threes: Process data + control engineers + analytics.

Exemplified by the four use cases spanning single controllers to many and analytics from monitoring to diagnostics, advanced analytics is an invaluable component for control and automation success. By integrating control engineer analytics within a comprehensive and extensible analytics platform, the collaborative value with other operations personnel is greatly enhanced, enabling a superior approach vs. niche-focused control analytics packages. Feature-laden advanced analytics, applied from a process control perspective and utilizing the engineer's expertise and process understanding, can be used to quickly uncover process value hidden in historian data and to accelerate process control benefits. HP

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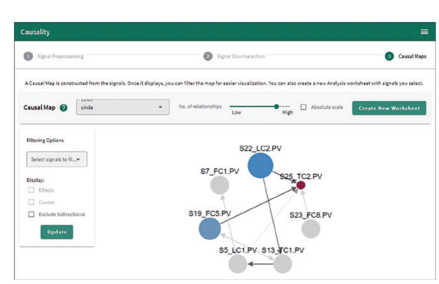

FIG. 8. Causal map generated for the dataset in **FIG. 7** accurately guides the user towards controller LC2 as the root cause of plantwide oscillations.

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Maintenance-free inline H_2 sensor for process industries

H2scan, a leading provider of proven, proprietary H_2 sensors and technologies for the H_2 economy, has begun shipping prototypes of its new HY-OPTIMA™ 5000 Series designed for process industries (FIG. 1).

The HY-OPTIMA 5000 Series analyzer provides a highly accurate, tolerant and affordable H_2 process gas measurement solution for industrial markets. It is optimized for emerging cost-sensitive applications like the power-to-gas market (H_2 blending into natural gas pipeline), electrolyzers and other process applications, including laboratories, alternative energy, H_2-cooled generators and turbines.

HY-OPTIMA 5000 sensors are based on the same patented autocalibration technology as H2scan's GRIDSCAN 5000 and legacy sensors. H2scan has sold and delivered more than 15,000 transformer sensors worldwide without a sensor needing recalibration since the company's launch in 2012.

The HY-OPTIMA 5000 Series uses a solid-state, non-consumable sensor for direct H_2 measurement in process gas streams. The HY-OPTIMA 5000 sensor package is available in a compact form factor weighing 1 lb and is 5.9 in. long and 1.6 in. wide/deep. This small size is due to H2scan's 1.2 MM-transistor application-specific integrated circuit (ASIC). The HY-OPTIMA 5000 is IP68 rated, can be submerged in up to 30 ft of water for 14 d and is marine compatible.

The inline H_2 process analyzer prototype features an auto calibration capability and is ideal for standalone or OEM integration into existing analyzers. It can be used in gas streams where real-time, H_2-specific measurements can enhance process plant efficiencies, improve yield and reduce maintenance costs.

Once installed and field calibrated, H2scan's patented auto calibration feature eliminates drift and the need for periodic calibrations and other maintenance. Communication with the unit is via serial communication using Modbus RTU over RS485.

The general purpose-rated analyzer measures H_2 directly in process gas streams with no cross sensitivity to other gases. Hazardous area rated products are planned for release in 2022.

The HY-OPTIMA 5000 models include the model 5031, 5033 and 5034 analyzers, all of which are intended for use in non-condensing gas streams and work with or without H_2 present.

Process simulation technology to support green energy

KBC (A Yokogawa Company) released Petro-SIM® 7.2 process simulation software, which is at the core of KBC's process digital twin. This release expands simulation capabilities for renewable fuels, an expanding variety of bio feedstocks, energy efficiency and environmental protection. Process design engineers benefit from the integration with MySEP technology, as well as new features for plant monitoring and operator training.

Petro-SIM technology offers operators quick wins for optimizing energy efficiency while reducing operating costs and emissions. By using Petro-SIM simulation software, organizations can create a process digital twin from feeds, through CO_2 producers, capture, transport and finally to storage. It connects real-time energy optimization with process/yield conditions, thermodynamics, electrochemical corrosion, scaling and remote equipment performance monitoring.

Petro-SIM software can now model renewable fuels. Operators can configure and optimize the use of low-carbon feedstocks, products such as LNG, bio-feeds and H_2 that power industrial facilities.

FIG. 1. H2scan's HY-OPTIMA™ 5000 Series analyzer.

360° process indication sensor

The new KingCrown process indicator (FIG. 2) from sensor and instrumentation specialist BAUMER presents critical information to operators easily and conveniently at a single glance, winning the 2021 Red Dot Award for outstanding industrial product design.

In process level measurement applications, five defined colors indicate whether the level has been reached, what medium is in the tank, or if a malfunction exists. Thanks to the 360° LEDs, this information is visible from all locations, even in

FIG. 2. The BAUMER KingCrown process indicator.

daylight or in challenging production environments, without a blind spot. This feature, along with a robust, minimalist design combined with Baumer's proTect+ impermeability concept, were the key factors in achieving the award.

In production environments involving high humidity, temperature changes or water spray, sensors require optimum impermeability and robustness, which is why Baumer sensors are designed in accordance with their proText+ concept. This concept is based upon a series of tests that first simulates the effects of aging before the sensors are subjected to the impermeability test according to the IP protection directives.

The robust stainless-steel housing with the LED crown protects the sensor's electronics from environmental influences and provides exceptional resistance to impacts or fracturing during installation or during operation in-situ, thereby minimizing the risks of downtime and failures.

Magnetic flowmeter added to instrumentation line

Leading industrial automation and IoT solutions provider OleumTech has launched an electromagnetic flowmeter as an addition to its fast-growing H Series hardwired process instrumentation line. The new OleumTech HEFM magnetic flowmeter delivers exceptional performance, reliability and accuracy ideal for oil and gas, petrochemical, and water and wastewater applications. The OleumTech Mag Meter offers best-in-class polytetrafluoroethylene (PTFE) lining material, a backlit local display interface and various self-diagnostic features for managing critical device health. The HEFM flowmeters can be custom ordered using a variety of line sizes, materials and power options to fit the needs of OleumTech end users.

OleumTech Mag Meter highlights include:

- Measurement is independent of fluid density, viscosity, temperature, pressure and conductivity
- Two measuring points inside the meter with no moving parts to eliminate pressure drop
- Reference accuracy: ±0.2% of reading
- Output signal options: RS485 Modbus / 4 mA–20 mA / 2 kHz–8 kHz pulse output
- Backlit LCD with integral push-button interface
- Process/lining temperature: –20°C–120°C (–4°F–248°F)
- Operating temperature: –40°C–70°C (–40°F–158°F)
- IP67 protection, robust construction and materials
- 1.5-in. to 6-in. line size options (custom sizes also available)
- AC or DC power supply option.

FIG. 3. The Chesterton Connect™ equipment monitoring sensor.

Equipment monitoring sensor for use in hazardous environments

The Chesterton Connect™ equipment monitoring sensor (**FIG. 3**) is now available in a version certified for use in hazardous environments. The latest release of Chesterton's IoT wireless monitoring product line is certified for use on equipment and structures in most hazardous environments dealing with high pressures, high temperatures and flammable liquids. Rated for Class 1/Division 1 (gas, vapor environments) and Class 2/Division 1 (dust environments) and IP66 for outdoor use, the new Chesterton Connect Sensor can be used in operators' most critical applications.

The Chesterton Connect sensor is easy-to-deploy and monitors rotating equipment such as pumps and heat exchangers, as well as structures such as tanks on a 24/7 basis for equipment vibration, equipment surface temperature, process pressure and process temperature.

Uniquely, the sensor monitors process fluid conditions that impact mechanical seals, which are often the first component to exhibit signs of imminent equipment downtime.

The Connect sensor communicates with a mobile application via Bluetooth. The app supports multiple sensors to provide a comprehensive view of a plant's equipment health to spot and fix issues before failure, often saving significant revenue and reducing downtime. The app also alerts the user when equipment pre-set operating limits are exceeded. The collected data from multiple sensors can be exported to the Chesterton Connect Cloud platform to spot trends and compare data to avoid equipment downtime and troubleshoot difficult-to-solve issues.

Chesterton Connect sensors keep workers safe by allowing them to check remotely on conditions and performance. The new version also allows remote monitoring in hazardous areas, so plants save on maintenance time and avoid potential accidents.

Next generation of FCC feed injectors

Lummus Technology launched its Micro-Jet™ Flex feed injectors, a new technological upgrade for fluid catalytic cracking (FCC) systems. This next-generation FCC feed injector provides a host of performance benefits, including lowering pressure drop, reducing droplet size, accelerating feed vaporization and increasing a unit's range of operation.

Refiners look for improved performance and ease of serviceability, while minimizing operational issues such as erosion and mechanical deficiencies. During the design of the Micro-Jet Flex system, the company focused on how to reduce or eliminate these roadblocks, while improving operators' yields.

The new Micro-Jet Flex feed injectors improve upon the original system, the successful Micro-Jet™ Plus feed injectors, delivering improved characteristics including optimal angle, correct exit velocities and thorough feed/catalyst contact necessary to maximize the performance of the unit. HP

An expanded version of Innovations can be found online at www.HydrocarbonProcessing.com.

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Technology and Business Information for the Global Gas Processing Industry

GAS PROCESSING & LNG

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Pipeline & Gas Journal

Lee Nichols, Editor-in-Chief/ Associate Publisher

The gas processing/LNG sector is investing in new technologies to mitigate carbon emissions from both operations and its supply chain. This road to decarbonization is prevalent throughout the oil, gas and energy industries.

In a way, natural gas is a step to decarbonize energy sectors around the world. Natural gas emits far less carbon dioxide (CO_2) emissions vs. other fossil fuels like coal or other petroleum products. Natural gas emits approximately 117 lbs of CO_2 per MMBtu vs. approximately 200 lbs of CO_2 per MMBtu for coal and more than 160 lbs of CO_2 per MMBtu for distillate fuel oil.[1]

Many nations and companies view natural gas as a bridge fuel to the use of renewable power, as well as the adoption of hydrogen to fuel various industry sectors. For example, many Asian nations are converting coal-fired power generation plants to use natural gas. The use of natural gas for power generation is a major step for these countries to adhere to ambitious net-zero emissions goals.

The adoption of cleaner routes to processing natural gas and LNG production is a major focus of this issue of *Gas Processing & LNG*. These practices and technologies are only some of the many ways the industry is adopting new methods to optimize operations and provide a pathway to sustainable production. **GP**

LITERATURE CITED

[1] U.S. Energy Information Administration, "Natural gas explained: Natural gas and the environment," online: https://www.eia.gov/energyexplained/natural-gas/natural-gas-and-the-environment.php

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Cover Image: LNG carrier discharging at a terminal. Photo courtesy of Trelleborg.

Shell says more LNG is needed to satisfy future demand

In its annual LNG outlook, Shell announced that additional LNG supplies will be needed to satisfy increasing natural gas demand, especially for Asia. According to the report, global LNG trade increased 6% in 2021 to 380 MMt. The U.S. led in LNG export market growth, increasing trade by 24 MMtpy year-over-year. On the demand side, China and South Korea increased LNG imports the most in 2021—China boosted LNG imports by 12 MMt in 2021 to nearly 80 MMt. Shell forecasts that global LNG demand will nearly double to 700 MMtpy by 2040.

Sound Energy to build micro-LNG terminal in eastern Morocco

To monetize natural gas production operations in the Tendara field, Sound Energy is planning to develop a micro-LNG plant in eastern Morocco. The gas processing and liquefaction plant will be designed, constructed, commissioned, operated and maintained by Italfluid Geoenergy Srl. First gas is expected to be delivered to the Moroccan market in early 2024—Sound Energy has signed a 10-yr take or pay deal with Afriquia Gaz.

Sempra signs deal for Mexican LNG projects

Sempra Energy's subsidiary, Sempra Infrastructure, signed an infrastructure deal with Mexico's Federal Electricity Commission to develop various projects in the country. The Memorandum of Understanding (MoU) includes the construction of the 4-MMtpy Vista Pacifico LNG terminal in Topolobampo, Sinaloa, Mexico; an LNG regasification terminal in La Paz, Baja California Sur; and the reinstatement of the 510-MMft^{3}d Guaymas-El Oro pipeline in Sonora. The LNG terminals will use natural gas feedstock imported from U.S. shale production.

Contract issued for construction of two natural gas power plants

Comisión Federal de Electricidad has awarded a few contracts for the construction of two natural gas combined-cycle plants. The 600-MW plants will be built in San Luis Rio Colorado and González Ortega, Mexico. The two plants will be built by Tecnicas Reunidas and TSK. The contract includes engineering, construction and commissioning of the two plants; Siemens Energy is supplying turbine technology for the facilities.

Both plants are scheduled to start operations in mid-2025. Once operational, the natural gas-fired plants will help Mexico decarbonize its domestic electricity sector, mitigating the use of heavy liquid fuels for power generation.

Germany speeds up LNG terminal build to wean off Russian gas

To help diversify natural gas imports, Germany has planned to develop three LNG import terminals. The country now relies heavily on piped natural gas from countries like the Netherlands, Norway and Russia—according to bp's *Statistical Review of World Energy,* Russia accounted for 56% of Germany's piped natural gas imports in 2020. However, due to Russia's invasion of Ukraine, Germany decided to not certify the Nord Stream 2 pipeline and speed up plans for the construction of new domestic LNG import capacity.

Over the past few years, Germany has announced three new LNG import terminals. These projects include:

- The 8-Bm^{3}y German LNG terminal in Brunsbüttel
- The 12-Bm^{3}y Hanseatic Energy Hub in Stade
- The 10-Bm^{3}y floating terminal in Wilhelmshaven.

At the time of this publication, Germany has approved the construction of the Brunsbüttel LNG terminal. The Brunsbüttel terminal was originally scheduled to begin operations this year but was delayed. Due to the events in the Ukraine, the terminal's approval process is being expedited, with construction to begin immediately.

Hanas receives approval to build new LNG terminal in Fujian

Hanas Group has received approval to build a new $830-MM LNG import terminal in Fujian province, China. The 5.65-MMtpy terminal will be in Meizhouwan port and contain one berth and two 200,000-m^3 storage tanks.

Tema LNG commercial operations to begin in 2Q

Ghana National Petroleum Corp. announced that the Tema LNG terminal is scheduled to begin commercial operations in 2Q. The terminal will use a floating storage and regasification unit (FSRU) vessel to import natural gas, which will be used for domestic electricity generation. Ghana plans to use the import terminal as a natural gas hub for West Africa.

Air Liquide to build largest biomethane production unit in the U.S.

Air Liquide plans to build a 380-GWh/yr biomethane plant in Rockford, Illinois. The facility will use biogas from Waste Connections Inc.'s solid waste treatment plant. The plant is scheduled to begin operations in late 2023. Air Liquide is also building a similar plant in Delavan, Wisconsin. That facility is expected to begin operations in 2Q of this year. Both projects will use Air Liquide's proprietary membrane technology, along with a complementary technology developed by Waga Energy. Once operational, these plants will increase Air Liquide's biomethane production capacity to 1.8 TWh/yr.

Portovaya LNG terminal to begin operations by 2023

Gazprom announced that the long-delayed Portovaya LNG terminal project will, most likely, be completed by the end of the year. However, at the time of this publication, it is unclear if Gazprom will delay the start of operations due to Russia's war with Ukraine. The conflict has resulted in several countries banning Russian energy supplies, including LNG shipments. With most of Europe closed to Russian LNG exports, it is unclear what the country will do regarding the start of the Portovaya LNG terminal. The 1.5-MMtpy terminal, located close to the Russia-Finland border, was originally scheduled to be completed in 2019; however, the project has been repeatedly delayed. The terminal is being built by Peton. The company was awarded a $1.62-B engineering, procurement and construction contract in 2016. Once completed, the LNG terminal will provide Gazprom an alternative LNG supply route to Europe, as well as provide natural gas to local customers and vessel bunkering.

Mexico Pacific LNG to double LNG terminal capacity

After securing MoUs from various offtakers, Mexico Pacific LNG announced it plans to double the facility's production capacity to 28 MMtpy. Located in Puerto Libertad, Mexico, the terminal will consist of six LNG liquefaction trains. At the time of this publication, the developer was working on converting the MoUs to binding offtake agreements. Mexico Pacific LNG plans to produce first LNG in 2H 2025.

Yancheng port LNG terminal to build six giant LNG storage tanks

China National Offshore Oil Co. (CNOOC) announced it will complete construction on six large-scale LNG storage tanks by 2024. The 270,000-m^3 tanks are being installed at the 6-MMtpy LNG terminal being built at Yancheng port in Jiangsu province, China. Once completed, CNOOC will be the third LNG operator in the province—PetroChina and Guanghui Energy each operate LNG terminals in Jiangsu.

Sorgenia and Iren to build new LNG terminal in southern Italy

To wean off imported Russian natural gas, two Italian energy groups—Sorgenia and Iren—are planning to expedite the construction of a new LNG import terminal in southern Italy. The 12-Bm^3y, located in the southern Italian port of Gioia Tauro, would cover nearly half of gas imports from Russia.

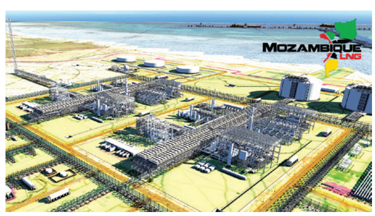
The project's permitting process was completed several years ago; however, the development of the facility has been on hold. If built, the project's developers announced that operations could begin within 3 yr.

In another move to cut off Italy's dealings with Russia, Italy placed a hold on its share of financing for Russia's $21-B Arctic LNG 2 project. Prior to Russia's invasion of Ukraine, the capital-intensive LNG export project was scheduled to launch in 2023 and reach full production capacity (nearly 20 MMtpy) in 2026.

Petronet to boost LNG import capacity

According to various news reports, Petronet LNG plans to add 9 MMtpy of LNG import capacity over the next 4 yr–5 yr. The company is increasing LNG import capacity by 5 MMtpy at its Dahej facility on India's west coast, as well as installing a 4-MMtpy FSRU in Gopalpur on the country's east coast. The Dahej terminal expansion will include the construction of a new jetty to import both LNG and propane. The propane will be used for a $1.6-B polypropylene plant to be built in Dahej. The additional LNG import capacity will help Petronet satisfy increasing demand for natural gas in India.

TotalEnergies to restart work on Mozambique LNG



In February, TotalEnergies Chief Executive Officer, Patrick Pouyanne, announced the company plans to restart work on the $20-B Mozambique LNG terminal project later this year. The capital-intensive project was halted in 2021 due to insurgent attacks, leading Mozambique to import foreign troops from nearby African countries to protect workers and infrastructure. TotalEnergies plans to restart work on the project this year, with first natural gas in 2024.

Venture Global selects Honeywell technologies for LNG pretreatment

Honeywell announced that Venture Global LNG will use a series of technologies from Honeywell UOP to remove various contaminants from natural gas to applicable LNG specification prior to liquefaction at its Plaquemines LNG export facility in Plaquemines Parish, Louisiana.

Honeywell UOP will provide engineering, procurement and fabrication services for the LNG pretreatment units which, when completed, will pretreat feed gas for the facility, which will produce LNG for export to markets in Asia, Europe and other locations.

The project will include a Honeywell UOP mercury removal unit and multiple trains each consisting of an acid gas removal unit and SeparSIV unit. Taken together, these modular units will remove mercury, CO_2, sulfur, water and heavy hydrocarbons to applicable LNG specification from 1.6 $Bsft^3$d of natural gas so it can be liquefied and safely transported to customers on ocean-going vessels.

The Plaquemines LNG terminal is located on a 630-acre site on the Mississippi River approximately 20 mi south of New Orleans, Louisiana (U.S.). according to Venture Global, the facility will have a total of thirty-six 626,000 tpy liquefaction trains in 18 blocks. The facility will include up to six pretreatment trains, three ship loading berths for LNG vessels carrying a capacity of up to 185,000 m^3, up to four 200,000-m^3 full containment LNG storage tanks, two 720-MW combined-cycle gas turbine power plants and additional infrastructure.

GNL Quebec's LNG project suffers another setback

In February, GNL Quebec's Energie Saguenay LNG terminal project was blocked by the Ottawa government. According to the Impact Assessment Agency of Canada's (IAAC) environmental report, the project would increase greenhouse gas emissions, have a negative effect on the nearby Innu communities and pose a significant risk to marine mammals in the St. Lawrence river.

Most likely, the IACC report is the final nail in the coffin for the project. The $14-B, 11-MMtpy LNG terminal has received significant opposition from indigenous communities and the local population.

Cheniere to start operations on Sabine Pass LNG Train 6

In early February, Bechtel passed custody and control of Sabine Pass LNG Train 6 to Cheniere. According to news reports, Train 6 has been commissioned and is set for commercial operations in Q2. Once operational, Sabine Pass LNG—located in Cameron Parish, Louisiana—will have a total LNG production capacity of 30 MMtpy.

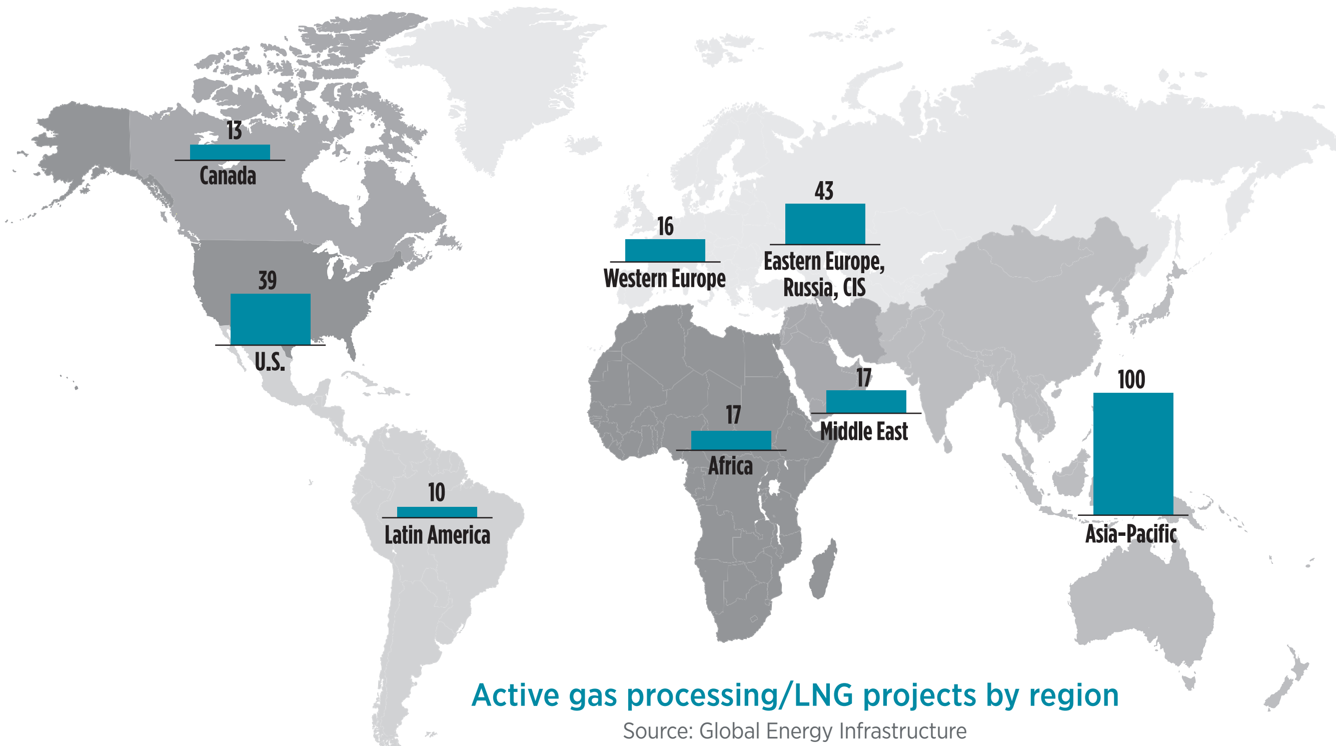
Cedar LNG commences FEED work

The Haisla Nation in partnership with Pembina Pipeline Corp. have awarded a FEED contract to Black and Veatch for the company's Cedar LNG project in Kitimat, British Columbia, Canada. Black and Veatch will work with Samsung Heavy Industries to provide an integrated solution for the floating LNG vessel.

Black and Veatch is responsible for the topside process plant, which includes the company's patented PRICO liquefaction technology. Samsung Heavy Industries is responsible for the hull and LNG containment system, along with integration of topsides, while also fabricating topsides modules designed by Black and Veatch.

FEED work is expected to conclude by the end of the year. Cedar LNG plans to begin operations in 2H 2027.

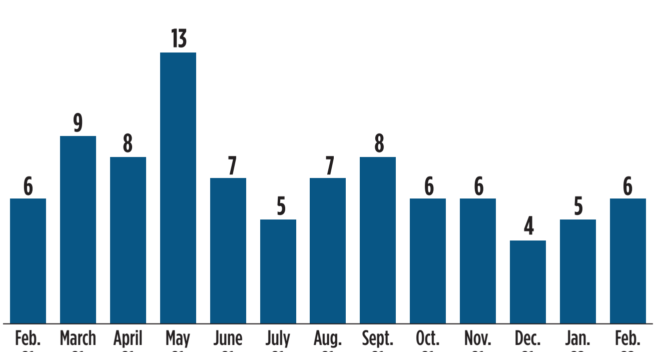
Gulf Energy Information's Global Energy Infrastructure database is tracking more than 250 active gas processing/LNG projects around the world. As shown in the world map, the Asia-Pacific region is the leader in active gas processing/LNG projects, doubling its nearest competing regions of Eastern Europe, Russia and the Commonwealth of Independent States, and the U.S. The region has also been the leader in new project announcements over the past year. The region is investing heavily in new natural gas infrastructure to satisfy increasing demand for power generation and to reduce carbon emissions in an effort to reach net-zero targets. **GP**



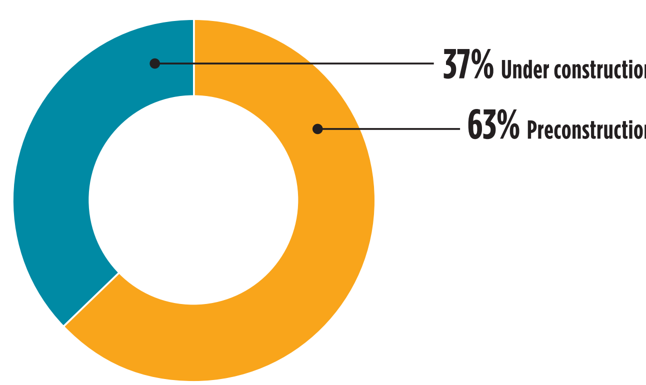
Active gas processing/LNG projects by region

Source: Global Energy Infrastructure

New gas processing/LNG project announcements, February 2021–February 2022



Active gas processing/LNG project market share by activity



Maximizing the performance of your ETRM system

T. KROH and **B. YORK,** Opportune, Tulsa, Oklahoma

Energy trading and risk management (ETRM) systems are vital for the support of business processes associated with trading energy commodities such as crude oil, refined products, natural gas, natural gas liquids (NGLs) and electric power, as well as facilitating the movement and delivery of those energy commodities and associated risk management activities.

While legacy ETRM software systems have filled critical functional gaps for the daily transaction of energy commodities over the years, many of these solutions are becoming obsolete or have not adapted to changing business conditions. Upgrading to modern concepts like cloud-centric architectures and/or digital strategies would serve companies well in that they can provide a scalable, reliable, affordable and fit-for-purpose technology stack that enables more effective trading and risk management capabilities.

What can energy companies do to stay ahead of the ETRM curve? *Gas Processing & LNG* (*GP*) spoke with Opportune's Directors of Process and Technology Teresa Kroh (TK) and Brad York (BY) to gain their insights on what decisions go into implementing an ETRM system, the intricacies of how to stay on top of ETRM solution upgrades, and how companies can stay competitive this year, among other topics.

GP: Where does the energy industry stand today in terms of ETRM technology? What needs to be done for companies to upgrade or enhance outdated systems that may hinder operational efficiencies?

TK: There are fewer players in the market and recommended solutions for companies that share a similar business model, so most companies do not need an extensive software selection process. Most of the systems that handle enterprise-level risk and trading still require on-premises servers and custom configurations, along with a user interface typically delivered through Citrix.

Most vendors provide software upgrades for free and encourage all customers to keep current with the latest release. However, every upgrade—even minor releases—requires targeted test plans and system downtime. There is a risk to continuing operations associated with every upgrade. Every upgrade requires solid project management supported by a team of people who understand the components of a successful upgrade, including the system hardware and delivery design, along with the testing and cutover requirements.

BY: The challenge I see with many companies in the energy industry is they will implement a system and think that is all they need to do. To keep up with technology, any company, regardless of the industry, must continuously upgrade and enhance its systems. This needs to be an ongoing process. I see companies that are on a platform that is more than 10 yr old because they were hesitant to upgrade. The longer they wait to implement or upgrade, the more expensive it is to implement. Technology changes rapidly and performance alone is probably worth the upgrades.

It is a bit of a pay now or pay more later. I have worked with companies that had a history of putting off upgrades and as a result, ended up implementing a different system—twice. The cost of that implementation and changing platforms was much greater than the cost of upgrading more frequently.

GP: How do you see ETRM technologies evolving in 2022 as they enable companies to better respond to the demands of the future?

TK: The next big shift should be to true software as a service (SaaS) delivery of functionality. Most of the players who claim cloud-based solutions are just hosting individual installations by the customer on offsite servers. The next major shift should include:

- SaaS-based solutions without the intensive server and software support teams per customer
- Core interfaces to the basic and necessary information to feed an ETRM system, including bills of landing (BOLs), pipeline tickets and nominations, invoices, pricing services and exchange-based trades
- Taking this one step further, the ability to confirm/approve trading activity and billing between counterparties that are using the same software without resorting to printing, email or other electronic methods.

BY: My experience is with one system, but I am aware of other similar systems. From my perspective, it seems that .NET technology is more flexible and easier to upgrade than older platforms. As performance improves, more complex calculations related to risk can be executed. As we talk about risk, which is important, we must also note the basics in the system must be there. If the data in the ETRM system is not reliable, there is no reason to try to use it for risk analysis.

Currently, there are only a few players, and most are a part of one company. A new software vendor will likely emerge, but it may be a bit difficult to enter the market.

GP: What are a few key things companies need to know before, during and after an ETRM system implementation?

TK: Having an experienced team dedicated to the coordination of design, testing, cutover planning and technical solutions is vital. This team requires project management, business users and server administrators, as well as developers who are

all knowledgeable regarding the ETRM being implemented. Expect the first months of post-implementation to require a tremendous amount of dedicated support. Implementation teams will never discover every nuance of data or business requirement that will happen post go-live. In addition, expect continual upgrades, improvements and enhancements.

Upgrades require re-implementation of any portions of the capabilities that were not translated one-to-one into the newer technology and require extensive testing of all custom interfaces or extensions. An upgrade provides an excellent opportunity to re-examine design or process decisions made during the original implementation. Look for opportunities for improvement that will enhance not just operations but business knowledge and processes.

BY: The most important thing any company needs with a software implementation is ownership and buy-in to the new or upgraded system. In general, people do not like change; if they are fighting change, it makes any implementation much more difficult. When implementing a system, dedicate the best employees to the project full-time. Most companies have key employees they do not think they can operate without, but those key employees could leave any day. Take the risk and put good people on the project. This will help ensure the right decisions are made during the implementation, and the best people are the ones that should know the system and they will if they are intimately involved in the system. When I say good people, this does not only apply to the people in the business, but also the information technology (IT) people who will be supporting the system after go-live.

An ETRM implementation is an excellent opportunity to clean up old reference data and to implement new processes. Implementation is not just about the system—it is also about the data they are starting with and the processes that can be a big improvement. If you are implementing a new ETRM system, be sure to select the right system for the business. The petroleum industry is very transparent as to which system it is using. Look around at your competitors and see what they are using and if they are using it successfully.

GP: How should technology impact a company's investment decision in ETRM systems?

TK: Performance is key to the successful use of an ETRM solution. Newer technologies typically provide better performance, freeing up the system and the people to go beyond logging the transactions necessary for operations and move towards using the data for analysis of a company's efficiencies and financial risk. Older versions of an ETRM system usually require older versions of all related supporting software. Upgrading allows the company to take advantage of a suite of upgrades across the database, server hardware and operating systems, and even Microsoft Word or Excel.

As an example, many companies are sitting on an older version of ION RightAngle. These older versions require outdated technologies and two user interfaces to access the portions of the software that have been ported. ION, like most major software companies, will not provide updates or fixes to these older versions. For many years, the releases were just ports of old functionality to newer technologies without any enhancements in capabilities. Without upgrading, companies cannot expect full support from the software vendor, and they will be unable to take advantage of enhancements.

BY: The investment is worth the dollars put into a system. Sometimes, it may bring efficiencies; however, the better way to look at implementation is not to reduce the employee count but to make the current people more efficient so they can provide better information for better decision-making. As mentioned earlier, a continuing investment will cost less in the long run than putting off investing in systems in the short term.

GP: What kinds of things should IT teams know before companies commit to upgrading ETRM systems in 2022?

TK: Design of the software delivery architecture is key to success. The biggest complaint around large ETRM software implementations is slow responsiveness. This slowness not only frustrates or impedes the users, but it can also snowball into software errors and issues in the background processors, which can cause data and interface issues. Our organization understands the importance of the correct server configuration and has worked with multiple clients to design the delivery architecture in a manner that will deliver the performance necessary for both user experience and software viability.

BY: As far as RightAngle goes, the important part to know is if they are in a version that is still partially in Powerbuilder; the switch to .NET is a big plus. Future upgrades are much easier to perform once the platform is all .NET. As with any initial implementation, an upgrade is also an opportunity to look at current processes and make some improvements. When any company does an initial implementation, it is a huge change to the entire organization. No matter how many training classes are given to the users, they cannot learn the system until they have used it for a while. Additional training during an upgrade gives the users a chance to learn things they may not have been told originally or were just too much to absorb.

Implementing or upgrading also allows a company to clean up and validate its reference data. Additionally, it is a good chance to make sure all inventory balances are correct.

GP: Why is quality control or developing a risk-informed testing strategy important when implementing or upgrading an ETRM system?

TK: Companies should maintain a set of well-documented test cases with expected outcomes. This documentation should continually be enhanced as processes change, interfaces are developed or issues are discovered. High-risk areas of functionality should have the most thorough testing requirements, with the level of risk defined by the severity of the impact to the business if a failure occurs or operations are interrupted. During an implementation, all test cases should be performed and signed off by business users. During an upgrade, more targeted testing can be performed with a concentration on known changes and high-risk components.

BY: Quality control is very important because if the outputs from a system are not correct, bad decisions can be made based on that data, which could be costly. Investment in a new system can be expensive, but if the implementation is not done well, the investment may be wasted. A quality implementation can make all the difference in how well an ETRM system works for an entity.

GP: What are some key considerations companies need to know when supporting their ETRM system? What might be some key IT enablers?

TK: ETRM systems require 24-hr support and monitoring. Resources must be assigned to respond to process failures to keep the system healthy. Most implementations are chugging through data or processes around the clock, so downtime means that there is now a backlog of processing, and it can be difficult to recover. Active notifications of failures should be implemented, when possible, instead of relying on monitoring to discover issues.

BY: Supporting an ETRM system should not just be about keeping it running, it should also be constantly considering enhancements. A support group should keep a prioritized list of enhancements requested by the business. Ideally, IT should facilitate brainstorming sessions with user groups as to how they can improve efficiencies. Involvement by the business with the vendor, if that is a possibility, is also a big plus. ION has user groups by domain, but many organizations have IT as the point of contact and the business is not connected. To make this relationship more effective, the schedulers, accountants and risk analysts should be attending the meetings conducted by the vendor, not just IT. Getting the business more involved in IT decisions helps the business buy-in and results in a better outcome.

Keeping the reference data correct is also important when it comes to supporting an ETRM system. The best results come from well-defined processes around any kind of reference data.

GP: What do you think the ideal ETRM system of the future will—or needs—to look like for companies to transform their business operations, enhance efficiencies, differentiate themselves from the competition and uncover new monetization opportunities? In other words, does the ideal ETRM system of the future require Internet of Things (IoT), cloud, automation, etc. capabilities, any one of them, or a combination of all of them? Why or why not?

TK: As previously mentioned, I can imagine an ETRM solution that involves a combination of the technologies listed and starts with IoT solutions to provide standard and readily available operational data from the pipeline, truck and rail operations that are shared across subscribers to an SaaS solution that communicates and confirms cross-subscriber activity, including physical transactions and billing.

With these technological advances, we could eliminate much of the cost associated with ETRM implementation, including custom interfaces, large software/hardware support teams and the processing required to communicate with counterparties. Companies could transform their business by analyzing readily available accurate operational data and concentrate on the core of their business profitability model instead of logging the operations in the supporting software.

BY: It is an interesting statement about the systems differentiating the companies from their competition. In past years, some companies believed their system was their differentiation, but as more companies have gone to package software and certain segments use the same system, that does not seem to be the case. I believe it is not the system but how well a company uses the system. The ETRM system is at the core of business operations, but many companies have add-on systems of some sort that help them to better utilize package software. I believe there are some big opportunities to use some web-based portals to communicate with customers. These allow the business partners to access information and keep the company's employees from spending all their time answering questions or sending out statements.

When the cloud was first introduced to ETRM, it did not work very well. However, it seems to be working much better now, and the concept of extra processing capacity when needed is great. The IoT could have more connectivity to gather quicker information such as meter readings and inventory levels. As ETRM technology gets more affordable, the ideal situation would be for data to flow from the field much more quickly than today. **GP**

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Managing methane: Has the answer been under our noses all along?

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More than 100 participating countries at the 26th UN Climate Change Conference of the Parties (COP26) signed the Global Methane Pledge, in which they agreed to take action to reduce methane emissions at least 30% by 2030 vs. 2020 levels. This focus on methane reflects its significant contribution to climate change. Scientists believe that methane has 28–34 times more warming power than carbon dioxide (CO_2). Oil and gas companies are among the leading methane emitters and will ultimately play a significant role in making good on the pledge.

Although the related costs and technical implications make it a challenging issue for oil and gas operators to address, reducing methane emissions is high on the industry's agenda. Leadership discussions at last year's ADIPEC conference shined a light on the need for the continued development and use of breakthrough technologies to improve sustainability, including reducing both methane and carbon emissions. The following question was posed: What new partnerships, business models and investments are required to create and effectively implement the right technologies?

It is reasonable to conclude that, against the backdrop of rising concerns about the impact of methane on the environment, oil and gas businesses are assessing how they can tap into technological advances to address the new emissions agenda. While the COP26 methane pledge reflected a country-level commitment, in the end, mitigating methane emissions will be driven by the businesses that emit it. How might the use of existing technology aid in reaching their goal?

If the 2030 target is to be achieved, industry players will have to explore ways to accelerate the process, and this entails a balancing act. According to Dr. Sultan Ahmed Al Jaber, Minister of Industry and Advanced Technology for the United Arab Emirates and Managing Director and Group CEO of the Abu Dhabi National Oil Co. (ADNOC), the global demand for oil and gas following the COVID-19 pandemic has increased to the point where the world will have to invest around $600 B/yr by 2030 to keep up with the anticipated demand. However, society cannot expect to unplug the energy systems of today and to automatically switch to the energy systems of tomorrow. Therefore, to achieve the 2030 target, a pragmatic approach is a must.

According to McKinsey & Company, oil and gas operations account for 20%–25% of anthropogenic methane emissions. If it is the responsibility of operators to take the tangible steps required to reduce emissions, then they must be empowered with good data, which is the foundation of robust decision-making.

The question arises as to whether all operators are making the most of existing digital technology in the associated arenas of monitoring, reliability and maintenance to understand and manage their methane emissions-related performance. According to literature, up to 85% of methane emissions in the oil and gas industry could be mitigated by 2030, using existing technologies.[1]

There is a case to be made for putting various pieces of the jigsaw puzzle together to create a cohesive view. This is a principle already embraced at the authors' organization. The authors have recognized that subsurface and topside digital technologies can form part and parcel of the same strategy.

Interactive petrophysics and correlation tools can monitor anticipated methane production levels, and, when integrated with geological understanding, these tools will equip the user with the data required to shape and implement mitigation measures for potential corrosion risks and leaks at the wellbore or caprock.

The authors' company's proprietary software tool[a] can deliver risk and reliability, while other software tools[b] can be used to ensure that inspection and maintenance work is focused, where necessary, on countering potential fugitive emissions from valves and other critical pieces of infrastructure.

Using asset monitoring, reliability and integrity technologies have a secondary effect. They serve to help operators minimize production losses, avert unscheduled downtime and reduce risks. Additionally, these technologies can also help to monitor and mitigate methane emissions, enabling operators to meet their sustainability goals.

Given the urgent need to address the primary causes of anthropogenic input to climate change, information sharing should be imperative (e.g., frontline experiences and lessons learned) between organizations to aid in reaching net-zero targets. This sharing of ideas and knowledge (such as identifying gaps that can be quickly closed by technological advances) can only help operators reach their emissions goals sooner. **GP**

NOTES

[a] Lloyd's Register RiskSpectrum software
[b] Lloyd's Register AllAssets software

LITERATURE CITED

[1] Jackson, R. B., *et al.,* "Increasing anthropogenic methane emissions arise equally from agriculture and fossil fuel sources," *Environmental Research Letters,* 2020.

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Lessons learned to optimize flare gas recovery systems in gas plant operations

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There are more than 100 flares spread across many operating facilities in the upstream and downstream oil and gas processing plants of Saudi Aramco. Flare systems are designed to provide the safe disposal of hydrocarbons that are either automatically vented or manually vented from process units. Flare systems gather vented gases and combust them to prevent release directly to the atmosphere.

Since Saudi Arabia started producing oil, associated gas has been flared. In the 1970s, the Kingdom recognized the value of the associated gas produced with crude oil. Major investments in building a sizable master gas system resulted in capturing and utilizing all the associated gas instead of burning it in gas flares. As a result, the Kingdom's annual flaring has been considerably reduced to facilities' routine and emergency flaring only. The environmental regulations from Saudi Arabia's Presidency of Meteorology and Environment require controls for smokeless flaring only from industrial activities, and there are no penalties for carbon dioxide (CO_2) emissions.

These standards apply just to routine emissions, and not to emergency, startup or shutdown events. Most Saudi Aramco facilities meet the environmental standard for smokeless flaring. The corporate roadmap on flaring was initiated as a response to the escalating cost of the new project proposals to make flares smokeless for routine operations in all of the company's facilities. The key element of this roadmap is to minimize flaring by implementing site-specific flaring minimization plans (FMPs) and installing a flare gas recovery system (FGRS) wherever feasible.

An FMP was initiated to reduce flaring from all Saudi Aramco facilities over a defined period by minimizing the frequency and magnitude of flaring. A comprehensive engineering standard for real-time measuring, monitoring, reporting and minimizing flaring was developed. Part of this minimization plan was to study the leakage rate to the flare system and to determine purge optimization. These two analyses play major roles in reducing facility emissions. Furthermore, the company's Process and Control Systems department issued design guidelines for FGRSs to give clear direction for selecting and applying new FGRS projects in all Saudi Aramco operating facilities. This guideline is in line with the Saudi Aramco corporate decarbonization strategy to reduce greenhouse gas (GHG) emissions.

The company has had several technologies in operation for a few years. Therefore, Saudi Aramco has updated its best practices with lessons learned from the startup and commissioning of compressor and ejector technologies at its facilities. This compilation of information provides additional insights that will enhance designs and proactively address common issues that can arise during the startup and operation of FGRSs at Saudi Aramco facilities.

FGRSs. Corporate management has recognized the need to approve a flaring roadmap, which calls for considering an FGRS if any facility is flaring more than 1 MMsft^{3}d of gas after implementing all flaring reduction measures. An FGRS will eliminate flaring as required for plant safety, provide routine process reliefs and return gases back to the process to prevent any leakages. Although FGRS technology is proven in industry, it was not adopted by the authors' organization in the past because, during that time, there were no compliance requirements for CO_2 emissions and there was a very low price to pay for sales gas. In recent years, however, the situation has changed. In the current industry environment, the primary drivers favoring FGRS projects include:

- Stricter global environmental regulations governing the emissions of GHGs, such as CO_2
- Environmental impacts and health effects of harmful emissions, such as nitric oxide (NO_x), sulfur oxide (SO_x) and volatile organic compounds (VOCs)
- Improved economic returns in recovered flared gas to the value chain, thus saving on plant fuel gas and steam consumption
- World Bank carbon credits for uneconomic FGRS projects, specifically for the elimination of CO_2 emissions, which can be traded for monetary gains—thus helping to improve returns on investment (ROIs) for projects
- Increased raw gas production costs, which makes FGRSs more attractive, since these systems recover flared gas and recycle it back to the process
- Rising sales gas costs, making FGRS recovery projects more viable
- Shortage of natural gas in the country
- FGRSs improve the reliability of main flare tips (important for larger-diameter flares that are prone to damage from operation at low daily flaring rates), enabling the main flare to stay in standby mode, which improves its reliability and life, and minimizes the recurring cost of flare tip replacement.

Additionally, one of Saudi Aramco's key values is citizenship, where the organization has a positive influence in communities and requires a demonstration of social responsibility. An FRGS pro-

vides an excellent platform to reflect this company image.

FGRS components. A flare gas recovery installation at an existing plant will consist of four main components. Brief descriptions of these component are below:

1. Compression technology is designed to recover flare gases for reuse in the existing processing facilities.
2. Staging devices safely divert routine flared gases to the FGRS, but not the emergency or abnormal relief loads. FIG. 1 illustrates the integration of an FGRS into the flare system.
3. A nitrogen-generation package is included to supplement existing nitrogen-generation capacity. Nitrogen will be used as a purge gas downstream of the staging device.
4. A control system within the package interfaces with the plant's distributed control system.

As shown in FIG. 1, the flare gas recovery unit ties into the flare gas header between the knockout drum and the staging device and pulls flare gas from the header whenever flow is detected. Basically, the staging devices enable safe operation of the entire system through sealing the elevated flares and providing backpressure in the flare header, allowing the flare gases to be routed to the FGRS.

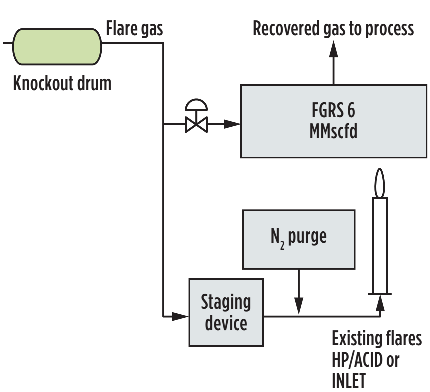

FIG. 1. The integration of an FGRS into the flare system.

Types of compression equipment. The choice of compression equipment will greatly influence the configuration of an FGRS. A detailed survey of existing technologies revealed that the compressor types widely used for FGRS applications include:

- Liquid-ring compressors with a variety of service fluids (such as water or diesel)
- Multi-staged screw compressors.

The major advantages of these compressor types include:

- They can handle a wide range of gases with varying molecular weights, with no effect on their performance.
- They can handle flow from zero to full capacity with a robust recycling system.
- They can tolerate liquid in the feed vs. any other type of compressors.

Ejectors. An ejector is a well-known technology for pressurizing gas by using a high motive source. The operating principle of the ejector is the pressure energy in the motive fluid, which is converted to velocity energy by an adiabatic expansion in the converging/diverging nozzle. Due to the pressure drop of the motive fluid, it will create a low-pressure zone before the mixing chamber. Due to this low-pressure zone, the suction fluid will start to move toward it and mix with motive fluid in the mixing chamber. The mixed fluid will enter the diverging portion of the ejector, where its velocity energy is converted into pressure energy (FIG. 2).

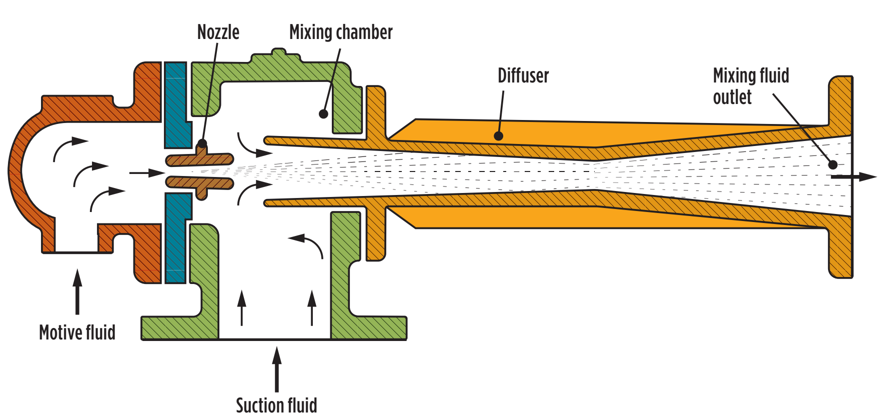

FIG. 2. An ejector schematic.

The authors' company has patented this technology to be utilized in a flare system to recover the wasted gas for further treatment or to generate energy. The team conducted several feasibility studies that approved the applicability of this technology to recover flare gas either by using a gas/gas or liquid/gas ejector. This technology was applied in oil-producing facilities and refineries, and it has successfully been used in gas-operation facilities by using amine solution as a motive liquid. When gas at sufficient pressures is available onsite, gas-motive ejectors could be an economical compression solution. Eductors or liquid-motive ejectors can also be considered and may use a closed-loop liquid circulation to provide the needed liquid-motive pressure. Eductors can also be used for gas sweetening purposes.

Recovering flare gas was not stopped by these compression types. The feasibility of flare gas recovery is considered the process philosophy for each facility. For example, each facility can recover flare gas by using an atmospheric compressor. As a result, hydraulic analysis was required to install a jump-over line from the flare header to the compressor suction pipe.

Challenges. Since Saudi Aramco started recovering flare gas, there have been major challenges. However, without these experiences, the authors would not be able to list all the lessons learned to overcome them.

One of the major challenges experienced in FGRSs is the oxygen ingress that resulted in the formation of solid particulates. As a result, these solid particulates blocked the suction strainers of the compressors. A sample was collected and sent to the research and development center for detailed analysis. It was discovered that elemental sulfur composition exceeded 99%.

Normally, elemental sulfur can be found in natural gas processing plants for two reasons: as part of the natural gas mixture coming from the source reservoir, or because of sulfur compounds reacting with oxygen, resulting in sulfur in its elemental form.

In natural gas, elemental sulfur is usu-

ally found in the vapor phase. Due to the increased carrying capacity that hydrogen sulfide (H_2S) provides to natural gas, its presence in the transported gas mixture helps with transporting elemental sulfur. Compared to methane, H_2S can carry more sulfur by three or four more orders of magnitude. Consequently, the probability of sulfur deposition in oil and gas processing facilities is increased.

The desublimation of elemental sulfur at certain pressure and temperature conditions is a major cause for deposition. Usually, the low concentration of elemental sulfur—within the parts-per-billion range—makes it more challenging to detect. In some cases, elemental sulfur desublimates intermittently at certain locations within the plant, causing difficulties in tracking the root causes of the problem.

In addition to elemental sulfur solubility, the oxidation of sulfur compounds could also be a major cause for elemental sulfur deposition. Testing of the demineralized water (in a liquid-ring compressor) indicates that the dissolved oxygen is within the acceptable parts-per-million range. Normally, oxidation of sulfur compounds like H_2S leads to the production of sulfur in the elemental form at certain pressure and temperature conditions. However, the source of oxygen is not limited to that in the demineralized water, as it could be air entering the system through leaks, or it could involve the availability of oxygen within the gas mixture transported to the FGRS. Operating the purge gas below the minimum safety requirements can be a major contributor of exposing oxygen in the system.

Also, part of enhancing FGRS reliability is to segregate flare headers with power operated emergency isolation valves (ZVs) should any upset occur in the facility. The FGRS is designed to recover the normal continued flaring; during an upset, the FGRS will be interrupted, resulting in a trip. Therefore, as part of reliability enhancement, the team proposed segregating feed ZV to the FGRS, along with sending a signal to close it in case the pressure in one of the flare headers increases near to the tipping point.

Prior to any change in the flare and relief systems, such as installing a flare gas recovery package, a study of full flare and relief systems should be carried out. Installing a flare gas recovery system could change the constant backpressure in the headers, which would affect the limit on PZVs allowable backpressures. Having the FGRS could also develop new critical overpressure scenarios that would need to be addressed. Further, in many applications, processes are equipped with continuous vent-to-flare systems, either in the process equipment or in the seal gas of the compression systems. Even small changes in operating pressures of the flare headers could lead to process interruptions from these services. Overall, any proposed changes in flare and relief system operations should be first assessed with appropriate studies on these systems. **GP**

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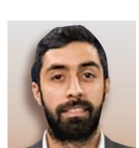

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The carbon conundrum: Digital technologies drive sustainability in LNG production and transmission

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Shell's *Prelude FLNG* (floating LNG) vessel is the largest floating production, storage and offtake vessel in the world, weighing as much as six aircraft carriers and stretching 1,601 ft. The offshore facility, which is currently anchored hundreds of miles off the coast of Western Australia, produces natural gas, then liquefies it at sea so that there is no need for long pipelines to deliver gas to processing plants onshore.

Of much concern to vessels like *Prelude FLNG* and to the larger LNG industry is a new initiative from the COP26 conference in Glasgow that is significantly increasing pressure on oil and gas to reduce gas emissions for cleaner energy production. Simultaneously, governments are also passing their own regulations to limit emissions, placing new caps and restrictions on production. On multiple fronts, LNG companies are facing rising demands to improve the efficiency and the sustainability of their operations.

The challenge is to accomplish these goals while avoiding massive new capital investments, which is why many LNG facilities have already turned to new digital tools to make the most of their existing assets and systems. Many of these use digital twin technology—a complete and integrated data model of all the engineering and operations information about the facility, which can be accessed using shared platforms by everyone working on, and remotely supporting, the site.

For example, Shell uses no-code operational digital twin technology to remotely monitor everything on the *Prelude FLNG* vessel, from the giant chain winches in the hull to the 50 MM liters (l) of ocean water used to cool the natural gas. From Perth, Shell engineers advise operators thousands of miles away, saving the company millions in transportation costs and enabling teams to spot potential issues before they become problems far out to sea. With its digital twin program, the company is not just building cleaner operations at sea, it is building more efficient, reliable and profitable operations, as well.

Site planning with the support of digital twins. Simply put, a digital twin is comprised of individual, focused twins—the process twin combined with the operational twin, and, for example, the financial twin, the asset registry twin, the human resources twin and so on—which, together, form an integrated system of systems.

Digital twin technology has been around for many years. In this time, industry users have built up a wealth of experience with these digital tools and have developed a much keener understanding of process stimulation. Cutting-edge users are adopting a layers-of-analytics approach, which moves beyond steady-state simulation models to more advanced, dynamic models fed with contextualized, high-quality, real-time data and associated intelligence. The results of the simulation models feed back to the operational twin to be operationalized in the form of targets and forecasts, which enables further layers of analytics, such as plan-vs.-actual analytics.

A process digital twin is a replica of a plant, with information about pumps, compressors, heat exchangers and any other relevant equipment modeled to mimic the workflow of the plant. This simulation can help improve plant efficiency throughout the entire plant lifecycle, from planning to process optimization to predictive analytics. Creating a process twin is a crucial step in optimizing the liquefaction process and detecting equipment problems before failures occur. The integration of the process twin and the operational twin, along with the other focused twins, produces a truly holistic digital twin of the business, which empowers remote and on-premises operator teams with the augmented intelligence they need to optimize operations and reduce emissions.

A digital twin also helps in the planning process for a new facility. The digital twin can evaluate hundreds of cases and scenarios within minutes to find a solution that will reduce emissions from the beginning, dramatically speeding up the engineering cycle. Modern steady-state simulation models can optimize design and the same model can be used later to monitor and optimize operations. It also enables engineers to model different scenarios and equipment locations in the front-end engineering and design (FEED) stage.

Steady-state simulation models can help optimize LNG plant design. Engineers can perform studies and look at different heat exchangers, distillation columns or flare designs to see which options will deliver maximum results, while increasing plant safety and minimizing both emissions from steady-state operations and fugitive emissions from operational failures.

For example, if an engineering team needs a certain throughput capacity for a reaction vessel, and the team is debating between using one large vessel or two smaller vessels, it can model the cooling and energy costs for the different scenarios, look at the pressure on specific lines and total throughput capacity to decide how the control design and operability of the two scenarios compare.

These types of major capital decisions create significant risks. A holistic digital twin can help companies manage the risk associated with huge capital projects by providing shared data and facilitating collaboration between project managers, vendors and suppliers. Simultaneously, a layer-of-analytics approach supports quicker and more accurate decision-mak-

ing, while promoting better knowledge sharing between the different teams. By this approach, streaming analytics in the operational twin integrate bidirectionally with higher-level analytics that use modeling and simulation, machine learning and other advanced digital tools to provide an accurate, single source of truth.

Reduced process variability for increased energy efficiency. Once the process twin is created for the engineering planning stage, construction is completed, and startup commences. Then, the engineering teams can hand that process twin over to the operations team to integrate with the operational twin to continue refining processes and proactively manage equipment to prevent unexpected shutdowns and equipment failures. The digital twin does this by reducing process variability, using predictive analytics to monitor equipment health and conduct overall process performance monitoring. For example, the operational twin can access pump curve data from the process twin and compare it against real-time pump efficiency. When the system detects a deviation from the best efficiency point, it issues an alert to operators so that they can address the issue immediately.

Advanced process control (APC) is used in multiple cryogenics operations to stabilize throughput and reduce variability from different feedstock compositions, ambient temperatures or equipment conditions. APC adjusts conditions and processes to manage changes in feedstock rate and quality, while also keeping plant operations within safe operating conditions and horsepower constraints.

At most LNG plants, implementing APC can deliver a 3%–4% increase in throughput and yield and a 2%–5% drop in energy consumption as measured by MMBtu/t. APC also reduces the need for operator interventions and improves plant stability.

A more proactive approach to maintenance with layers of analytics. Along with the increasing sophistication of digital twin capabilities, improvements in predictive analytics are being made, as well. This enables more precise recommendations earlier and requires less historical data to accurately anticipate failures. If a piece of equipment fails in production, it can cost tens to hundreds of thousands of dollars to replace the asset. Unplanned plant shutdowns can cost upwards of $1 MM/d in lost production revenue. However, plant overruns can quickly add unexpected costs at an even faster rate, to say nothing of possible safety implications.

Unplanned shutdowns can hit the natural gas industry especially hard because LNG trains are extremely cold during operation. If a shutdown occurs, it will require more time to restore full production than it would for operations near ambient temperatures. A layers-of-analytics approach enables the modeling of rotating equipment using machine learning and advanced pattern recognition with streaming and predictive analytics integration.

Advanced predictive analytics compares real-time operations data to the digital twin models and flags any subtle deviations from normal equipment behavior. This early warning system means that reliability and maintenance teams can identify, evaluate and address problems before a major breakdown takes place. It also means teams can make an informed assessment when a particular piece of equipment starts showing signs of wear.

TransCanada—one of the largest LNG pipeline operators in the world—calls this ‘fixing little things;” things that can have million-dollar impacts if they are neglected. TransCanada manages 31,000 mi of pipeline across North America with a very diverse fleet, ranging from small reciprocating 300-hp units to 35,000-hp turbines, while tracking more than 16,000 streams of data.

Like Shell’s *Prelude FLNG,* TransCanada has also adopted a layers-of-analytics approach. The company’s analytics journey began with relatively modest objectives: digital asset construction and basic anomaly detection. Once TransCanada had built a solid foundation of operational data management and streaming analytics, it began to evolve its analytics overlay with more advanced algorithms and event frame generation to monitor key performance indicators (KPIs) and performance metrics. By 2017, these layers of analytics had detected 129 anomalies and netted more than $10.65 MM in prevented expenses.

Maximizing throughput with real-time performance monitoring. There is one other key area where digital twins can reduce the carbon footprint for LNG operations: process performance monitoring. From the beginning, an LNG plant is designed using APC to operate at maximum safe efficiency based on the characteristics of the assets, plant layout and production pipeline. However, as soon as operations start, variations in feedstock and fuel gas composition or changes in ambient conditions inevitably impact throughput, which can then affect operating profits.

Performance monitoring studies live operations to resolve non-linear relationships that may impact plant throughput, including process constraints, feedstock and mixed-refrigerant composition, to reconcile material use and look at energy and equilibrium balances around a piece of equipment. With better tracking of real-time performance, pipeline companies can also identify inaccurate instrument readings. This acts as a data validation layer, while also pinpointing material and energy loss locations so operators can quickly find the source of any fugitive emissions that occur.

More-efficient LNG, a more sustainable future. LNG producers and pipeline operators are facing demands to make their operations greener and more sustainable. Simultaneously, they must maximize performance, minimize costs and delays, and ensure efficient organizational operations. To achieve all these aims at once, natural gas companies need to synchronize every facet of their business, from planning and engineering to operations and onward. By reducing emergency flare-ups and unplanned shutdowns, a holistic digital twin enables producers to thread that needle—reducing energy usage and emissions while increasing performance and efficiency all at the same time. By embracing a layers-of-analytics approach, LNG companies can help ensure efficient use of the world’s precious resources. **GP**

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Investigations of high pressure drop observed in ASU columns

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The measured pressure drop of columns in air separation units (ASU) is often reported as being higher than the predicted pressure drop. Particularly for high-pressure (HP) columns, the difference can be up to four times higher, depending on the operating pressure of the column. To investigate the difference, the operation data of recently revamped HP columns were collected; then, vapor and liquid loads as well as their physical properties were generated using a process simulation tool. Thereafter, a proprietary hydraulic rating tool[a] was utilized to predict the dynamic pressure drop caused by the column internals. The use of the differential pressure transmitter and its connecting piping inside the cold box was also scrutinized. It was deduced from calculations that the average temperature of gas in the differential pressure transmitter (PDT) piping located inside the cold box was more than four times higher than the temperature of gas inside the column. The resultant different gas static head at the two locations leads to the deviation between the measured and the predicted pressure drop.

Since the 1980s, structured packings have progressively replaced trays, first beginning with the crude argon (CAR) column and low-pressure (LP) columns. Around 2011, in China, structured packings eventually became a default option for HP columns.

It was determined that the pressure drop of columns in the ASUs was higher than what was predicted by the hydraulic rating tool[a]. The extent of the reported deviations was inconsistent—the typical difference was ~20%, which was initially believed to be within the accurate parameters of pressure drop correlations. When the packings-equipped HP columns began to operate nationwide, the observed deviation jumped. For a 550-kPa HP column, the measured pressure drop was three times higher, and for an HP column operated at 900 kPa, the measured pressure drop was four times higher.

Pressure drop in a column is caused by two factors: dynamic pressure drop and static pressure drop (commonly called gas static head). Dynamic pressure drop is the resistance of column internals, such as packings, to gas flow.[1,2] The pressure drop decreases with declining gas throughput, and reaches zero if gas flow stops. For a packed column, the dynamic pressure drop is closely linked to packings capacity—e.g., for a proprietary structured packing series[b], 5.5 mbar/m and 12 mbar/m correspond to 90% and 100% capacity, respectively. Therefore, the dynamic pressure drop measured from a plant is typically used to monitor packings hydraulic performance. In contrast, the static pressure drop is caused by the pressure exerted by gas weight over a certain height.

The gas density in ASU columns can reach 40 kg/m^3, depending on the operating pressure of the columns, and structured packings generate much less dynamic pressure drop than trays. Therefore, the gas static head can contribute a significant portion to the total pressure drop for ASU packed columns. The proprietary hydraulic rating tool only calculates dynamic pressure drop, so the gas static head must be manually added to the dynamic one to obtain the total pressure drop of a column. However, the measured pressure drop in ASU plants matches neither the proprietary hydraulic rating tool's[a] predicted dynamic pressure drop nor the total manually calculated pressure drop. Rather, it lies between.

Although the deviation does not cause any practical challenges to column design and operation, a joint investigation between the authors' companies began in early 2020 with the objective of benefitting the ASU industry.

Data collection and analysis. Among the various columns in an ASU, the HP column is the best option for investigation: the simplest HP column consists of only one feed (e.g., the compressed air feed) and two products (i.e., liquid nitrogen at the top and oxygen-enriched liquid at the bottom). The high pressure drop observed in HP columns will not be masked by the inaccuracy of any pressure drop correlations.

In the last 2 yr, the authors' companies have successfully revamped HP columns from tray to structured packings, and the details of the first project were published elsewhere.[3]

The operation data of two identical revamped HP columns in a plant were collected in June 2021. The vapor and liquid loads and their physical properties were generated using a process simulation tool, and then the dynamic pressure drop of packings was calculated using the proprietary hydraulic rating tool[a]. The gas static head inside the HP column was calculated manually using Eq. 1:

$$\Delta P_{static\ pressure\ drop\ in\ HP} = \rho_g \times g \times h \quad (1)$$

where,

ρ_g is the average gas density in the HP column,
g is the gravitational acceleration and h refers to the total vertical distance between the pressure taps.

The relevant data are listed in **TABLE 1.** The measured pressured drop is about three times the dynamic pressure drop pre-

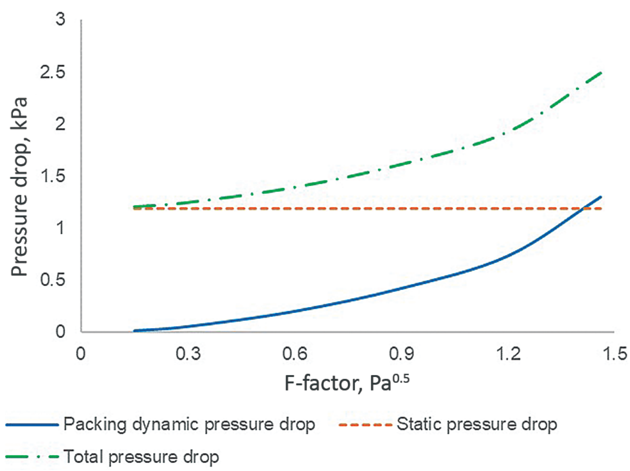

FIG. 1. Pressure drop of the top bed against F-factor.

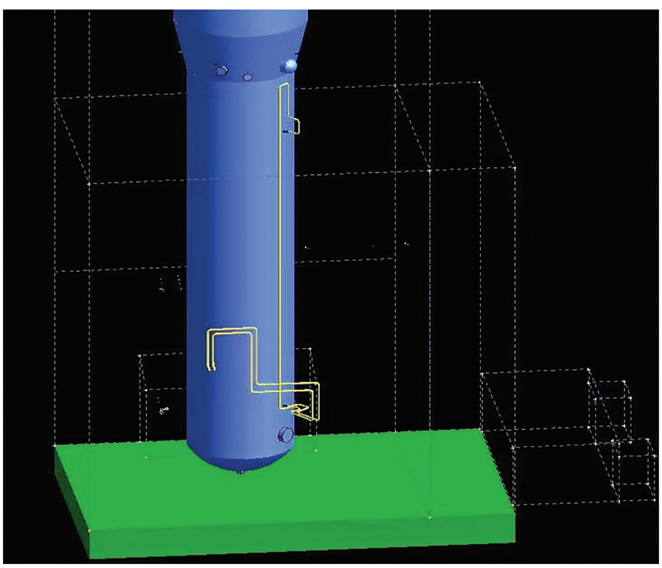

FIG. 2. PDT taps and piping connected to the HP column in the cold box (other equipment is omitted for clarity). Note: the dotted lines indicate the contour of the cold box.

dicted by the hydraulic rating tool for both units. It can also be seen that the gas static head contributes to > 70% of the total pressure drop in the column, as the gas density is between 22.7 kg/m^3 and 22.4 kg/m^3 in the 14-m tall columns.

The HP columns investigated consist of two beds, and **FIG. 1** illustrates three different types of pressure drop for the top bed against F-factor, which can be calculated according to Eq. 2:

$$\text{F-factor} = (V/A) \times \sqrt{\rho_g} \tag{2}$$

where,

V stands for volumetric flowrate of gas (m^3/sec),
A for the tower cross-sectional area (m^2) and
ρ_g for gas density (kg/m^3).

The change in gas density is < 1% when the operating pressure of the HP column varies between 545 kPa and 551 kPa (the result of change in throughput). Therefore, it is reasonable to assume that the gas density and the subsequent static pressure drop do not vary with the F-factor, as shown in **FIG. 1.**

Due to a very different temperature in its connecting piping, the measured pressure drop by a PDT in an ASU cannot be used to judge packing hydraulics permanence directly.

TABLE 1. Pressure drop for the HP columns at the same load

	Unit 1	Unit 2
Predicted dynamic pressure drop, kPa	1.111	1.111
Predicted gas static head in HP, kPa	2.852	2.852
Total pressure drop, kPa	3.963	3.963
Measured pressure drop by PDT, kPa	2.96	3.16

Using two pressure transmitters, the pressure drop in a column can be measured by subtracting the top pressure from the bottom one. The advantage of this arrangement is its simplicity, as the two transmitters (top and bottom) do not need to be connected by a vertical line. However, a disadvantage can be inaccuracy. In this instance, the typical error of 0.1% on the pressure measurement for a column operating at 550 kPa is expected to be +/– 0.55 kPa for both the top and the bottom measurements. Therefore, the pressure drop difference will have an error of +/– 1.1 kPa. A measurement of 3.0 kPa (as shown in **TABLE 1**) with an error of +/– 1.1 kPa is useless. This method is inadequate, and not recommended in this case.[4] A differential pressure method is preferred.

A proprietary transmitter model[c] was used in the plant. It is known that, in general, a PDT reading does not indicate the gas static head in a column, as the gas static head in the PDT connecting piping would offset the one in the column. However, in some situations, corrections must be made when the PDT reading has to be rigorously interpreted. For instance, in many applications, inert gas such as nitrogen (N_2) is used to purge the piping to prevent condensation of process gas due to lower temperature outside the column. The detailed correction method can be found in literature.[1]

Since the pressure drop measured by the PDT in the ASU was much higher than the predicted dynamic one, corrections were conducted to verify whether the deviation can be explained. A particularity of cryogenic distillation (as found in an ASU) is that the temperature of the piping connecting to the PDT is higher than the temperature inside columns, thus no inert gas needs to be injected into the piping. Instead, process gas enters the pressure piping directly.

To evaluate the impact of the gas static head on the PDT reading, the space arrangement of PDT piping connected to the HP column in the cold box was retrieved from installation drawings. The piping in Unit 1 is shown in **FIG. 2** and simplified in **FIG. 3.** The representative piping with numerous bends counters thermal expansion and contraction in a range of more

TABLE 2. Static gas head at different temperature of PDT piping

Assumed T in PDT connecting piping, °C	-80	-60	-40	-20	0	20	30
Gas density of N_2 in the piping at 555 kPa, kg/m^3	9.81	8.85	8.07	7.41	6.86	6.38	6.17
Static head in PDT connecting piping, kPa	1.24	1.12	1.02	0.94	0.87	0.81	0.78
Predicted PDT value, kPa	2.72	2.85	2.95	3.03	3.1	3.16	3.18

than 200°C (392°F) between normal operations and startups/shutdowns. The transmitter is on the lower platform for ease of access ($h1$ at 10,465 mm and $h2$ at 2,400 mm). On the day when the operation data were recorded, the ambient temperature was 27°C (81°F). It should be noted that that the detailed pressure piping design may vary among licensors.

Unfortunately, like in many other plants, the PDT piping local temperature was not available despite the fact that the temperature of the cold box foundation is closely monitored. A different approach was taken in corrections: match back the temperature of the piping based on the measured pressure drop.

A large temperature gradient between the column and the wall of the cold box was expected, as the temperature inside the HP column was close to –180°C (–292°F), in contrast with the 27°C (81°F) ambient temperature. By varying the temperature, the gas density of a pure N_2 at 5.51 bar was calculated and is tabulated in **TABLE 2.** As shown, the gas density changes with temperature, and its values in the temperature range investigated are at least two times smaller than the gas density in the HP column. Similarly, the density of the O_2-enriched gas is also calculated at the corresponding temperature. The static pressure drop in the piping is calculated based on Eq. 3:

$$\Delta P_{static\ pressure\ drop\ in\ the\ tubing} = \rho_{g1} \times g \times h1 + \rho_{g2} \times g \times h2 \qquad (3)$$

where,

ρ_{g1} and ρ_{g2} refer to gas density in the upper and lower piping, respectively. Then, the predicted pressure drop by the PDT is obtained by correcting the dynamic pressure drop (Eq. 4):

$$PDT = \Delta P_{packing\ dynamic\ pressure\ drop} + \Delta P_{static\ pressure\ drop\ in\ HP\ column} - \Delta P_{static\ pressure\ drop\ in\ the\ piping} \qquad (4)$$

When the piping temperature is assumed as –40°C (–40°F) and 20°C (68°F) for Units 1 and 2, respectively, the calculated PDT values match the site PDT readings at a unit capacity of 20 kNm^3/hr.

It is worth mentioning that in the two identical units, the main equipment and their space arrangements are exactly the same, but the space arrangements of instrument piping are not. **FIG. 4** exemplifies the impact of the temperature of PDT piping on different types of pressure drop. It can be seen that the predicted PDT reading rises with increasing temperature in the PDT piping, and the slope is steep at lower temperatures. It is also apparent that the piping for Unit 2 is closer to the wall of the cold box. The calculations at other loads deduced the same temperature for each unit, confirming the plant data acquired are consistent and of quality.

Assuming a uniform piping temperature in the calculations above is correct for qualitative analysis. However, considering the isometric of the pressure piping in the cold box and its variations in different projects, precise quantification of the gas static head in the piping requires temperature gradient along the piping.

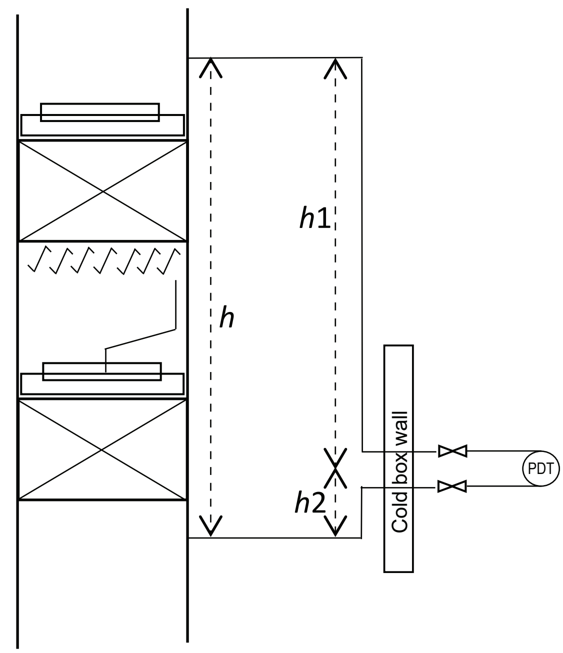

FIG. 3. The simplified HP column and PDT piping.

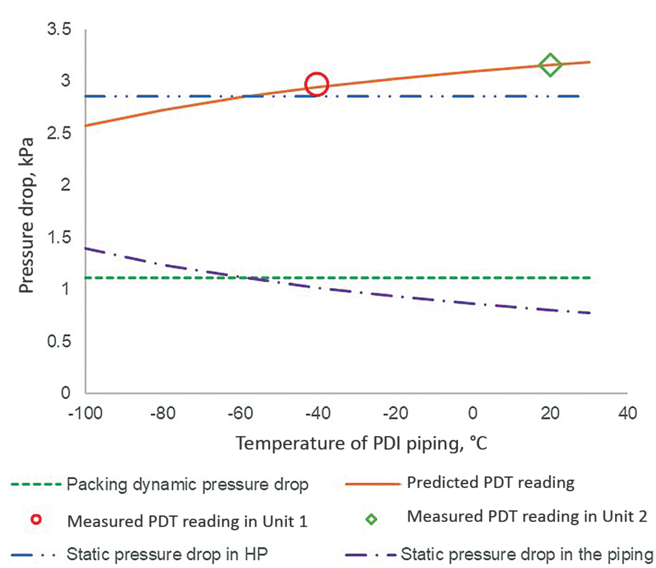

FIG. 4. Pressure drop of the HP column against the temperature of PDT piping at a capacity of 20 kNm^3/hr.

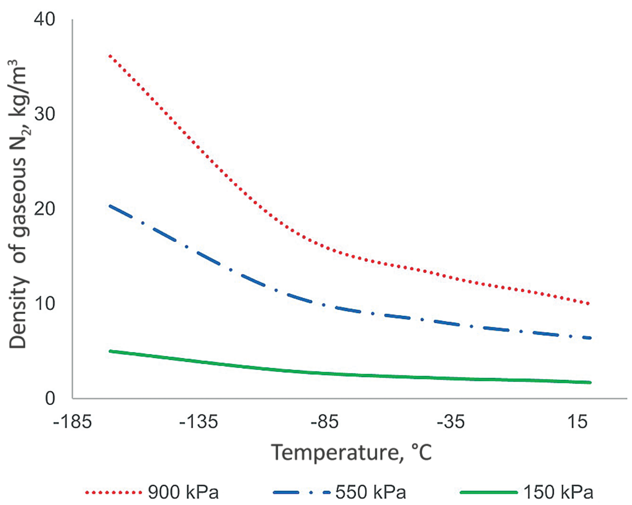

FIG. 5. Density of gaseous N_2 at different temperature and pressure.

In addition to the variation associated with the temperature gradient along the piping, the location of the transmitter outside the cold box—which is also project dependent—affects the gas static head in the piping to a small extent. Specifically, in the case investigated here, the gas in the upper piping is nearly pure N_2 with trace of oxygen (O_2) and argon (Ar), and the gas in the lower piping consists of 37.8% O_2 and 1.6% Ar. As the gas density is a function of its composition, if the location of the transmitter changes, then the gas static head in the piping would also change, according to Eq. 3.

Inferences. Despite being a theoretical exercise, the calculations in this paper are adequate to conclude that the deviation between the predicted dynamic pressure drop and the PDT reading is caused by the difference between the gas density in the HP column and the gas density in the pressure piping due to the great temperature difference. The larger the difference in gas density, the greater the deviation.

This can also explain why only a 10%–30% deviation has been observed with the LP and CAR columns. First, the gas density difference is still the primary reason for the deviation. Due to much lower operating pressure, the gas density in the LP and CAR columns are in the range of 5 kg/m^3–8 kg/m^3; therefore, the gas static head becomes a smaller portion of the total pressure drop (the curves of static and total pressure drop would shift downwards in **FIG. 1** in such a case). Using gaseous N_2, **FIG. 5** illustrates the impact of column operating pressure on the gas density at different temperatures.

Takeaway. Due to the temperature gradient along the piping of the differential pressure transmitter and its varying position in the cold box, it would be challenging—if not impossible—to deduce from a PDT reading either the dynamic pressure drop of packings or the total pressure drop of a column. Hence, unlike in other applications, PDT readings in an ASU cannot be used to judge how far the columns are from flooding, nor can they provide any input to process simulation and upstream equipment sizing, significantly limiting typical uses. To obtain the correct pressure drop for ASU columns, zero calibration[5] can be considered based on gas density. However, this requires the gas temperature in the pressure piping.

To investigate the difference between the PDT reading and the predicted pressure drop, the operation data of HP columns in the ASU were collected and processed. It was determined the deviation is caused by significant temperature difference between the HP column and the differential pressure transmitter piping. The PDT reading corresponds neither to the dynamic pressure drop of packings nor the total pressure drop of the column. **GP**

NOTES

[a] Sulzer's Sulcol™
[b] Sulzer MellapakPlus™ series
[c] YOKOGAWA EJA110E

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Soft startup of best practices for commissioning of amine plants

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The startup and commissioning of hydrocarbon plants can present unique challenges that, if not anticipated and addressed in the pre-commissioning and commissioning periods, will inhibit plant startup and increase the difficulty of achieving product specifications in a timely manner. This article provides details on potential multiple challenges during commissioning, as well as a method to avoid these challenges by applying a soft startup concept on a massive scale. The acceptance criteria and successful results of the soft startup concept are detailed here.

Plant A sought to avoid or reduce the common commissioning challenges of a new amine system (e.g., gas treatment facility), including foaming, the presence of unwanted debris or materials in piping and vessels, etc. To ensure the short- and long-term reliability of an amine system facility, Plant A elected to implement a soft startup concept on a massive scale, where the amine circuits are filled completely with pure demineralized water (rather than amine), then pressurized by nitrogen (rather than fuel gas) up to the operating pressure. This was completed for multiple safety and reliability reasons to:

- Test system tightness with a safer medium (nitrogen, as compared to fuel gas)
- Debug the associated process control and emergency shutdown (ESD) systems
- Test the functionality and reliability of all rotating equipment
- Clean the system of any remaining debris and suspended solids prior to charging with expensive solvent into the unit
- Limit the potential for future foaming incidents.

During the soft startup, circulation is started in both cold and hot modes to ensure that all debris and suspended solids are removed from the pipe walls, fittings, valves and other equipment and vessels, and the debris and suspended solids are caught by the strainers and filters. This approach was successfully utilized in the other amine units.

Amine system process description—acid gas removal unit. The gas enters the treating train through the inlet filter separator. The separator is provided to remove any particulate matter or traces of liquids that may be received with the incoming gas. Without a spare separator, a bypass valve (sized for full flow) is installed to allow maintenance servicing of the separator.

The gas coming from the inlet filter is fed to the amine contactor for carbon dioxide (CO_2) removal. The contactor is a tray column divided in two sections. The bottom amine absorber section consists of trays. The lean amine is fed to the top tray and the rich amine is withdrawn from the bottom of the tower. The upper section of the contactor comprises three trays and is used as a water washing system to absorb any amine entrained in the gas from the bottom absorber section. The second pass reverse osmosis water is circulated around the trays by pumps.

A continuous make-up of fresh reverse osmosis water is fed to the top of the section while excess water is drained from the column water wash chimney tray to the rich amine flash drum. The outlet for the wet sweet gas from the top of the amine contactor is routed out of the gas treating train to the natural gas liquids (NGL) recovery unit.

Rich amine from the contactor bottom is fed to the rich amine flash drum, a horizontal vessel with a top-mounted vertical absorber equipped with random packing. The hydrocarbon gases dissolved in the rich amine are flashed off, washed through the absorber and routed to the thermal oxidizer. As the flashed gases pass through

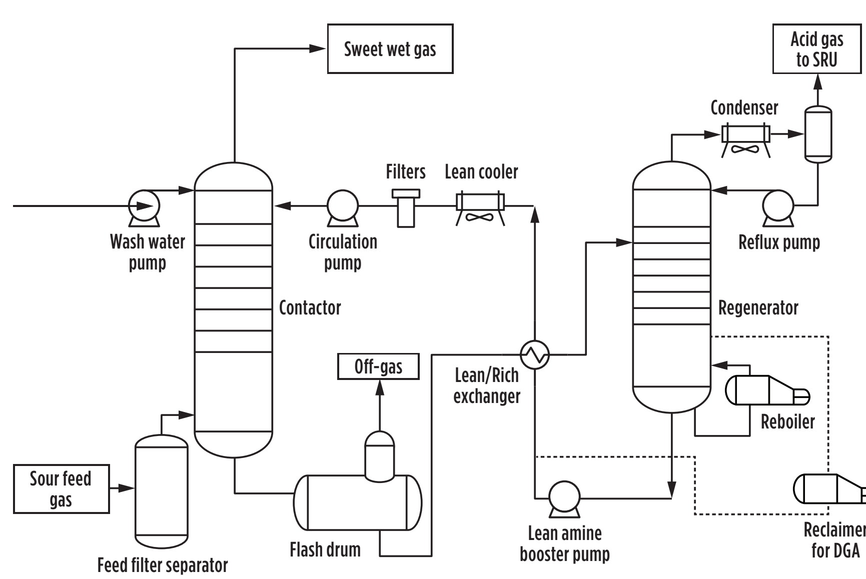

FIG. 1. Typical PFD for an acid gas removal unit.

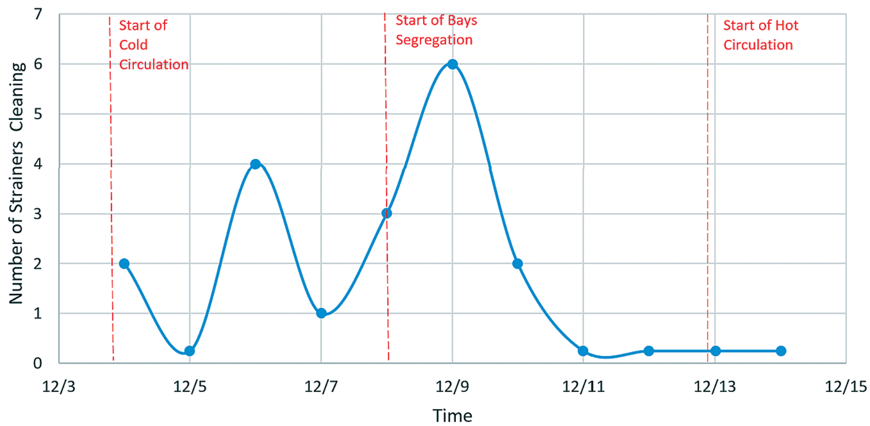

FIG. 2. Frequent strainer cleaning for amine System A.

FIG. 3. The progression of water clarity by the samples collected from amine System A.

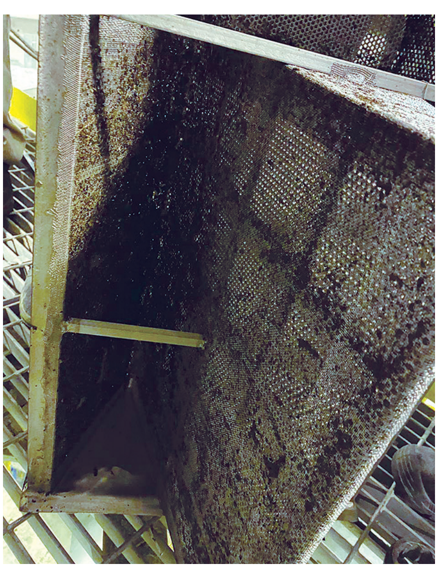

FIG. 4. Dirt accumulation in pump strainers.

the absorber, any amine entrainment is removed by the counter flow of the water withdrawn from the amine contactor top section. The rich amine coming from the flash drum is heated up through the lean/rich amine exchangers and fed to the amine stripper.

The stripper is a trays column with two once-through exchangers that take feed from the column bottom chimney tray. Heat for the amine stripper reboilers is supplied from the low-pressure hot water system. The gases from the top of the stripper are cooled in the amine stripper overhead condenser and water is condensed in the reflux drum. The acid gas is routed to the CO_2 compression unit. Any organic phase present will be separated in the reflux drum and manually discharged to the wet hydrocarbon burn pit.

The reflux pumps return the condensed water as reflux back to the stripper top tray and, during the regeneration cycle, partially to the amine reclaimer. The lean amine from the stripper bottom is routed toward the amine contactor by booster pumps. Before being fed to the contactor, the lean amine is cooled through the lean/rich amine exchanger and the lean amine cooler. The lean amine circulation pumps boost the pressure and return the lean amine to the amine contactor. Pumps route a fraction of the circulating lean amine (~15%) to the precoat filter package, and filtered amine is rejoined to the lean amine flow.

The amine reclaimer is provided to periodically regenerate the circulating amine. A fraction of the circulating lean amine from the booster pumps (~1% of total amine pumped flowrate) is fed to the amine reclaimer. The reclaimer operates at 360°F (182°C) and controls the amine solution boiling temperature by an adequate flowrate of reflux water from the amine stripper reflux pumps. Amine and water are recovered to the stripper as vapors coming from the top of the reclaimer, while degraded amine components are left on the vessel bottom. This sludge pond also receives the amine slurry from the amine precoat filters. The acid gas removal process configuration is shown in **FIG. 1.**

Amine system process description—acid gas enrichment unit. The wet acid gas is first cooled in a cooling water chiller and then enters an inlet separator to remove liquid hydrocarbons from the gas stream. The acid gas then enters the bottom of the contactor trayed column and flows upward through the absorber in intimate countercurrent contact with the selective amine solution, where the amine selectively absorbs hydrogen sulfide (H_2S) acid gas constituents from the gas stream. Before leaving the contactor, the CO_2 gas passes through a water wash section.

The rich amine solution is sent from the bottom of the contactor via the rich amine pump to the lean-rich amine heat exchanger, before entering the top of the stripper column. A part of the absorbed acid gases will be flashed from the heated rich solution on the top tray of the stripper. The remainder of the rich solution flows downward through the stripper in countercurrent contact with vapor generated in a steam reboiler. The reboiler vapor (primarily steam) strips the acid gases from the rich solution.

The acid gas and the steam leaving the top of the stripper pass through a condenser, where the major portion of the steam is condensed and cooled in an air cooler. The acid gas is separated in the reflux drum and sent to the acid gas enrichment unit.

The lean amine solution from the bottom of the stripper column is pumped by a booster pump through a lean-rich heat exchanger and then through air coolers to the top of the contactor. To ensure cleanliness of the circulated selective amine solution in the contactor, a 15% slipstream of the lean solution is passed through a mechanical filtration system.

Acceptance criteria for soft startup. A soft startup can be declared successfully completed when at least two of the following three criteria are achieved:

- The frequency of strainer cleaning is reduced to less than one cleaning activity per strainer every two days.
- Qualitative proof that water samples are getting clearer every operating day for three consecutive days, then stable/no change for an additional day.

- Stable water chemistry parameters are achieved for at least two consecutive days through lab sampling.

PLANT TEST RUNS

Amine System A. Amine System A was placed under a soft startup on December 4, 2019, and in cold circulation until December 13, 2019. During the cold circulation phase, four of the lean amine cooler bays (50%) were isolated and amine was run through the other four bays to increase turbulence and ensure cleanliness (**FIG. 2**). After the system was stabilized and the in-service bays were deemed clean, the bays were isolated and the other four bays were put in service. The switching practice continued until consistent readings on the pump strainers were achieved. Following that, amine System A was placed in hot circulation.

As previously highlighted, one of the acceptance criteria of the soft startup is sample bottle clarity. **FIG. 3** shows the progression of water clarity by the samples collected from amine System A. It can be clearly seen that the water in the system became clearer and cleaner during the soft circulation period.

The first sample (on the right) shows the highest level of dirt. Moving to the left, the samples progressively show an improvement in water quality.

Fin fan tubes were cleaned by limiting flow to four bays at a time, which allowed turbulence flow across the fin fan tubes. During this cleaning, a sudden increase in deferential pressure was noticed in all pump strainers due to dirt accumulation, as shown in **FIG. 4.**

Lab analysis of water chemistry parameters (**TABLE 1**) from amine System A showed them becoming stable for at least four consecutive days through lab sampling, indicating that amine System A became cleaner.

Amine System B. The system was placed under soft startup on December 4, 2019, and in cold circulation until December 13, 2019. During the cold circulation phase, two of the lean amine cooler bays (50%) were isolated and amine was run through the other two bays to increase turbulence and ensure cleanliness. After the system was stabilized and the in-service bays were deemed clean, the bays were isolated and the other two bays were put in service. The switching practice continued until consistent readings on the pump strainers were achieved. Fol-

TABLE 1. Lab analysis for water samples, amine System A.

Analysis	Amine System A			Unit
	12/11/19	12/12/19	1/14/19	
Conductivity	428	430	422	micros/cm
TDS	210	215	211	ppm
TSS	3	3	7	ppm
Total iron	0.98	1.1	1.08	ppm

lowing that process, amine System B was placed in hot circulation (**FIG. 5**).

Fin fan tubes were cleaned by limiting the flow to two bays at a time, which allowed turbulence flow across the fin fan tubes. During this process—as with System A—a sudden increase in deferential pressure was noticed in all pump strainers due to dirt accumulation.

Lab analysis of water chemistry parameters from amine System B (**TABLE 2**) showed them becoming stable for at least four consecutive days through lab sampling, indicating that amine System B became cleaner.

TABLE 2. Lab analysis for water samples, amine System B.

	Amine System B			
Analysis	12/11/19	12/12/19	12/14/19	Unit
Conductivity	718	708	708	micros/cm
TDS	359	354	354	ppm
TSS	5	9	5	ppm
Total iron	0.41	0.47	0.45	ppm

TABLE 3. Lab analysis for water samples, amine System C.

	Amine System C			
Analysis	12/11/19	12/12/19	12/14/19	Unit
Conductivity	66	74	80	micros/cm
TDS	33	37	40	ppm
TSS	17	2	2	ppm
Total iron	3.14	1.5	1.42	ppm

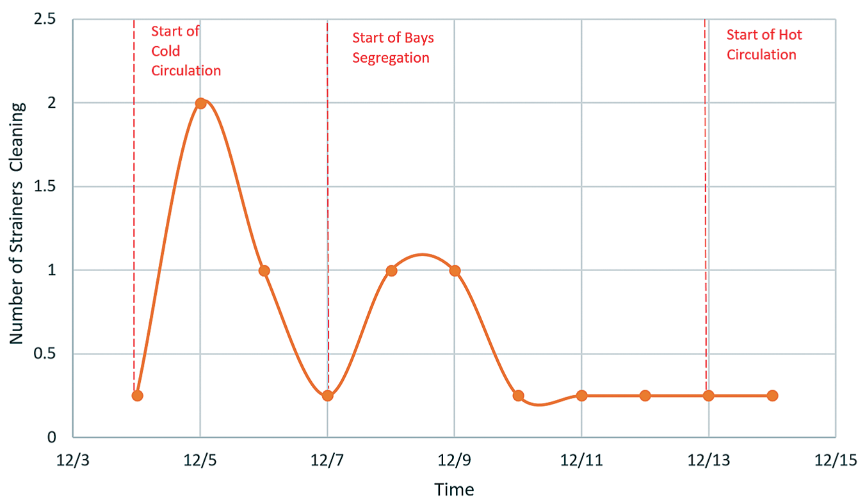

FIG. 5. Cleaning frequency for amine System B.

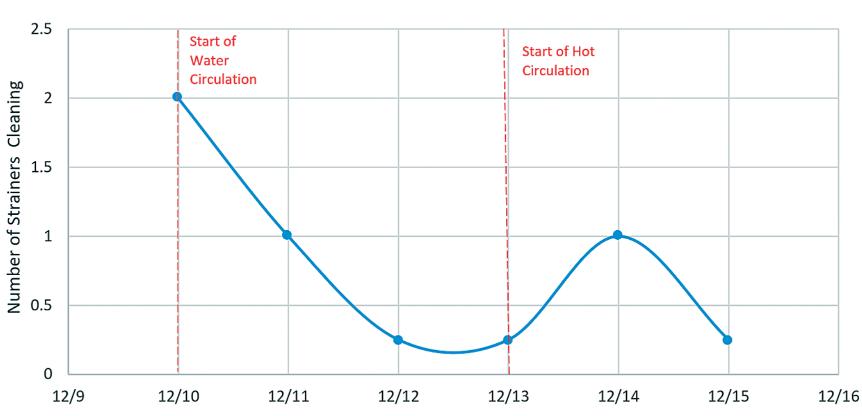

FIG. 6. Frequent strainer cleaning for amine System C.

Amine System C. The system was placed under soft startup on December 10, 2019, and in cold circulation until December 13, 2019. The system was then placed in hot circulation. During the water circulation phase, the amine System C circulation pump strainers were cleaned frequently. The cleaning practice continued until the system become clean.

Lab analysis of water chemistry parameters from amine System C (**TABLE 3**) showed them becoming stable for at least four consecutive days through lab sampling, indicating that amine System C became cleaner.

Takeaway. Based on results from experimental runs on three units, the soft startup concept has proven advantageous, helping avoid common commissioning challenges of a new amine system (e.g., gas treatment facility)—including foaming, the presence of unwanted debris or materials in piping and vessels, etc.—and ensuring the short- and long-term reliability of an amine system facility. **GP**

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LNG plant emergency response: Prepare, remain vigilant, execute

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Have you ever heard of an "emergency reaction team?" The likely answer is "No." Despite similar dictionary definitions for the words "react" and "respond," much has been written about the differences between the two terms. Generally, a reaction is hasty, emotionally-driven and does not involve higher thinking. Conversely, response is methodical and meticulous, driven by preparation, and involves careful evaluation of the situation and application of past knowledge and training to address it—just what is needed in an emergency.

Responding vs. reacting is even more important in a liquefied natural gas (LNG) plant where the potential for fire and other hazards is present. The goal of any company operating such a facility should be to apply the science of emergency response preparation, readiness and execution to potential emergencies rather than simply reacting when something unexpected occurs.

Internationally recognized organizations such as the Society of International Gas Tanker and Terminal Operators (SIGTTO) and the International Group of Liquefied Natural Gas Importers (GIIGNL) have issued publications with guidance on LNG safety, including emergency response as one layer of safety. Additionally, countries hosting LNG companies issue regulatory guidance for LNG operations. In the U.S., the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) provides guidance on how to prepare a response for potential LNG emergencies in the Code of Federal Regulations (CFR) Title 49 Part 193—Liquefied Natural Gas Facilities: Federal Safety Standards.

Where potential exists for "smoke and fire," specialists like those shown in **FIG. 1** respond not only for firefighting, rescue and emergency incidents, but also for compliance with the PHMSA Part 193 regulations. The author's Corpus Christi, Texas-based, not-for-profit company offers a unique perspective on the science of LNG regulatory compliance and emergency response based on its deployment of full-time, in-plant emergency response teams in two United States Gulf Coast (USGC) LNG export facilities.

Prepare—The U.S. LNG regulatory mandate. The U.S. PHMSA regulations for LNG under 49 CFR Part 193[1] are written in a way that describes what to do without defining exactly how, providing flexibility to LNG facilities that may range in size from a small, peak-shaving plant to a multi-train, world-scale export terminal. The regulations address emergency response primarily in three paragraphs[1]:

- Paragraph 2509, Subpart F, "Emergency procedures," requires operators to determine "the types and places of emergencies other than fires that may reasonably be expected to occur at an LNG plant," and to manage each of these by following "one or more manuals of written procedures." The paragraph also identifies four specific items that the procedures must cover: responding to controllable emergencies, recognizing uncontrollable emergencies and promptly notifying local officials, coordinating with local officials in preparation of an emergency evacuation plan, and cooperating with these same officials during evacuations and emergencies that require mutual assistance.
- Paragraph 2713, Subpart H, "Training: Operations and maintenance—Personnel

FIG. 1. RTFC first response crew ready for action.

It is important to recognize that targeting an LNG fire with water will only increase the rate of vaporization and make the fire bigger. Dry chemical, such as Purple-K, and high-expansion foam are important tools for fighting LNG fires.

qualifications and training," requires that all permanent maintenance, operating and supervisory personnel be trained on the characteristics and hazards of LNG to conduct the emergency procedures under paragraph 2509 related to their assigned functions, provide first-aid, and numerous other non-emergency items.
- Paragraph 2717, Subpart H, "Training: Fire protection," covers fire emergencies and requires maintenance, operations and supervisory personnel to be "trained according to a written plan, including plant fire drills…" to "…know the potential causes and areas of fire; know the types, sizes and predictable consequences of fire; and know and be able to perform their assigned fire control duties…"

Preparing an emergency response plan (ERP). The next step is understanding the manuals and procedures that address emergencies. Because the regulations dictate that a manual is required and training must be administered, personnel are left to deduce the manual contents based on the guidance.

LNG facility ERPs, in accordance with regulations, may contain the following:
- **Identification of emergency events that may occur.** This satisfies the regulations regarding types and locations of emergencies. LNG spills, refrigerant spills, fires, weather events and other emergencies are included.
- **Description of facility emergency organization.** Many companies elect to have facility personnel only fight "incipient" fires and provide basic first aid, calling onsite or external emergency responders for events that become uncontrollable. This is where industrial emergency response specialists, such as the author's company, have a role.
- **Description of offsite emergency organizations and agencies.** This includes fire departments, ambulance services, law enforcement agencies and others.
- **A contact list for company and external personnel, organizations and agencies.** This list must be routinely updated as changes occur and includes all company personnel involved in emergency response and all external parties that may be involved in a response or require notification regarding an emergency.
- **Definitions of controllable and uncontrollable emergencies.** Any PHMSA inspector will look for this in the manual. According to Part 193,[1] "Controllable emergency means an emergency where reasonable and prudent action can prevent harm to people or property." Uncontrollable emergencies are deduced to be cases where "can" is replaced with "cannot."
- **Detailed descriptions of facility emergency and communications systems.** This includes fire and gas detection systems, firewater systems, emergency shutdown systems, plant radios, public address/general alarm (PA/GA) systems, etc. Drawings and illustrations are included, usually in appendices, where needed.
- **Evacuation procedures, training and drill guidance, and requirements for coordinating with local officials.** Each of these address specific Part 193 requirements.
- **Site-specific emergency response procedures.** This is often included as an appendix to the ERP and addresses all emergency events identified for the facility. Many U.S. facilities utilize the National Incident Management System (NIMS) incident command system (ICS) structure.
- **Appendices of supporting documents referred to in the ERP.**

LNG facility ERPs are best written to address exactly what the Part 193 regulations require—this ensures satisfactory regulatory agency inspection results. When a U.S. LNG production facility is coupled with an export marine terminal, the United States Coast Guard (USCG) under 33 CFR Part 127[2] also requires an emergency manual specific to the marine facilities under USCG authority.

Remaining vigilant: What a third-party emergency response organization can bring. Preparation is fruitless if skills are allowed to atrophy; maintaining a state of readiness is just as important as preparing for emergencies. For plant maintenance, operations and supervisory personnel expected to fight incipient fires and only participate in supporting roles at larger emergencies, this means initial training on LNG properties, emergency procedures—usually including ICS, first aid, evacuation, fire protection and fire drills—with continuing instruction at intervals of not more than 2 yr. Drills are especially important since the role-playing of "table-top" and "simulated" emergencies aids understanding and recall. Part 193[1] mandates that plant fire drills provide personnel "hands-on experience in carrying out their duties under the fire emergency procedures…"

For most facilities, plant personnel utilize their skills gained in training to manage controllable emergencies but call for help with escalating or uncontrollable emergencies. This may involve an external fire department, an internal company emergency response team (ERT), or a specialist, full-time, in-plant emergency response team such as the 24/7 emergency response staffing solutions provided by the author's company.

Many industrial facility operators have evaluated these options and realized that while external fire departments train on industrial fire-fighting and HAZMAT (hazardous materials) response, they focus their efforts on their primary customers: residential and commercial entities. Any operations manager that has ever fielded an ERT will testify to the challenges of paying overtime for coverage in

the plant and training, trying to operate the plant when half the operators suddenly leave to respond to an emergency, and attempting to maintain the proficiency of personnel who are only "part-time responders." Many operators have concluded that a specialist, third-party organization that solely focuses on emergency response is the best option.

For an organization that specializes in emergency response, the preparation and readiness to deal with an emergency is much more extensive. For example, a new recruit at the author's company will receive ~14 wk of training covering National Fire Protection Association (NFPA) Codes and Standards 1, 10, 11, 12, 12A, 12B, 25, 30, 59A (LNG), 329, 471, 472, 600 (Facility Fire Brigades), 704, 1001, 1002, 1005, 1006, 1062, 1071, 1072, 1081, 1404, 1405, 1451, 1500, 1561, 1670, 1961 and 1983, in addition to various parts of the U.S. Occupational Safety and Health Administration (OSHA) 29 CFR 1910/1926 requirements and the American Heart Association CPR/AED First Aid courses. This training provides full coverage for industrial/marine/structural firefighting, emergency vehicle operations, HAZMAT response, rescue, inspection of fire protection equipment and ICS. Additionally, all recruits are required to obtain their medical EMT-B (Emergency Medical Technician, Basic) certification, which adds 6 wk of training. Paramedic training is optional. Continuing education maintains proficiency.

Equipment must also be kept in readiness (**FIG. 2**). A good third-party organization will conduct ongoing inspections of all fire hydrants, fire detection/alarm systems, building extinguishing agent systems, emergency lighting and exit signs, fire extinguishers, fire hose carts and reels, firewater main block valves, firewater hoses, foam carts and trailers, foam systems, storage tank-fixed systems, fire monitors, mobile apparatus and equipment, fire pumps, self-contained breathing apparatus (SCBA), air supplied respirators, control room emergency air, halon/dry chemical systems, deluge systems, eyewash/safety showers, fire doors and HAZMAT suits, among others. These systems and equipment require inspection, and having an onsite emergency response team conduct the inspections offsets part of their cost by eliminating the need for other third-party inspectors.

Additionally, a good third-party emergency response organization will offer respirator fit testing/training, air monitoring, marine spill response, fire extinguisher training, incipient emergency response training, confined space entry pre-planning, industrial hygiene assistance and emergency procedures consultation. They will ensure regulatory compliance for emergency procedures, fire-fighting and regulatory mandated drills, providing training to plant personnel on all regulatory mandated initial and recurrent training and conducting periodic drills.

Responding when called upon. Before discussing how to respond to an LNG emergency, it is important to understand the properties of LNG. LNG is mostly composed of methane (CH_4) and normally boils at approximately –260°F (–162°C), expanding ~600 times when the liquid turns to vapor. CH_4 is the first to boil off, with ethane (C_2H_6), propane (C_3H_8), butanes and other substances following at higher boiling point temperatures. The flammable range of LNG vapors in air is 5 vol%–15 vol%, and LNG vapor normally will not explode unless confined, such as a leak in an enclosed space.

LNG vapors are colorless; however, because they are cold, they often condense moisture from the air, creating a white cloud that, in very humid environments, can be a good indication of a flammable mixture (**FIG. 3**). The initial vaporization rate after a spill of LNG can produce 10 $ft^3/min/ft^2$ of surface area (i.e., a 10-ft × 10-ft pool of LNG will create ~1,000 ft^3/min of vapors). A similar

FIG. 2. RTFC ensuring emergency equipment readiness.

FIG. 3. RTFC Training Academy live spill LNG training.

FIG. 4. Application of vapor dispersion water sprays and Purple-K dry chemical.

spill of LNG on water generates significantly more, with as much as ~5,000 ft^3/min of vapor generation.

For emergency response purposes, spills are classified as land/water and confined/unconfined. LNG facility design includes countermeasures for confining LNG spills for containment and, therefore, for vaporization rate stabilization. Unconfined spills are always producing vapor at the maximum rate at the leading edge of the spill where fully warm surfaces are encountered. These spills spread in a particular way as they flow downhill as a liquid, but create a vapor plume that travels downwind, creating a potentially broad and rapidly expanding vapor cloud.

LNG vapors produce a plume that can travel a significant distance before diluting to a point within the flammable range, and extreme amounts of radiant heat can be produced if ignition occurs. LNG vapors burn at ~2,426°F (~1,330°C), which is approximately 1.3 times the temperature of burning gasoline. In addition to the fire hazard, cryogenic LNG and vapors will cause severe frostbite if they contact human skin.

Any LNG facility emergency response plan will include "LNG spill with/without fire" cases. This is the primary aspect that makes LNG facilities different from other industrial process locations. For the LNG spill without fire case, cryogenic fluid contact with both personnel and equipment/structures poses great concerns. Unique "rules" for fighting an LNG fire include:

- Targeting an LNG fire with water will only increase the rate of vaporization and make the fire bigger.
- A condition called rapid phase transition (RPT) can occur with LNG, resulting in large "non-burning explosions" of vapor that break the sound barrier and make a loud "pop" noise, so it is important not to "puncture" the surface of boiling LNG or "break" the cushion barrier as it rapidly boils and moves across a surface.
- LNG fires are fought similarly to liquefied petroleum gas (LPG) fires, by isolating hydrocarbon sources (closing valves) and bleeding down or blowing down the pressure behind the leak or spill. It is preferrable to let the fire burn itself out rather than extinguish it and have it potentially re-ignite.
- Dry chemical, such as Purple-K, and high-expansion foam are important tools for fighting LNG fires (**FIG. 4**). Foam will not extinguish the fire, but it covers the surface, lowers the vaporization rate and allows a more controlled burn with less radiant heat. Dry chemical does not stick to the surface of LNG and smother the fire like in typical liquid hydrocarbon spills—it inhibits the chemical chain reaction, preventing the continuous burning of the gases even though a flammable range is present.
- Due to the immense heat released from an LNG fire, it is important to consider positioning cooling water sprays and water application (fire streams) on adjacent equipment and structures, if possible.
- A condition called boiling liquid expanding vapor explosion (BLEVE) can occur when a fire impinges on a container, such as a pressure vessel or even a blocked-in pipeline holding the fluid, causing weakening of the container walls and catastrophic failure. Fortunately, this is considered a low probability event for LNG due to LNG tank design with insulation layers and storage at atmospheric pressures with well-designed pressure relief systems.
- Rescue emergencies at LNG facilities are similar to any facility; however, because many LNG facilities include a marine terminal, water rescue is added to trench and high-angle rescue scenarios.

Takeaways. Successfully resolving an emergency in an LNG facility begins with a thorough understanding of the applicable LNG regulations, continues with thorough and exceptional planning for potential emergencies, requires deliberate measures to stay prepared and ready for a real emergency, and ends with successful execution based on preparation and training.

While each facility operator must choose how it will ensure these successful outcomes, an excellent option is to contract a specialist, third-party organization with a sole focus on emergency response. These organizations not only maintain personnel preparedness through initial and recurrent training, but also continually inspect emergency equipment and systems in the LNG facility to be sure they are equally as ready to perform as the personnel. This is an investment that will pay dividends when needed most. **GP**

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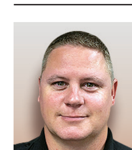

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MAURY HUDSON has 30 yr of hydrocarbons processing experience with more than 15 yr in LNG, where he helped place RTFC for emergency response in two USGC LNG export facilities. He consults for various industry clients, including LNG facilities.

Digital transformation in LNG requires a long-term, data-driven approach

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The energy transition has begun, and natural gas, especially in its liquefied form, promises to play a key role in enabling the shift to a greener and cleaner global power picture. The potential is there, but the LNG industry finds itself facing continually mounting pressure from all fronts—the foremost being the rise in production levels while prices continue to fall, putting companies in a cost crunch at a time when investment is sorely needed.

The solution to this conundrum lies within the LNG industry's ability to leverage three concepts: efficiency, profitability and sustainability.

The LNG players who have managed to tackle these challenges are the ones who have succeeded with a longer-term digital roadmap and an investment in a data operations (DataOps) platform on which to build their digital solutions. They have understood the underlying power of connecting data from across their operations and putting it to work to optimize decision-making, rather than driving one-off digital projects intermittently.

There are three commonalities seen among the digital leaders in the LNG industry. The first is that these frontrunners have stopped seeing their data as something in silos and, rather, have made concerted efforts to bring data together into one, bigger, connected picture. Second, they have used that data to gain real-time situational awareness about their operation. Lastly, they can act on that awareness to drive better, more sustainable and more cost-effective decision-making. The following will show these aspects in practice.

Break down the data silos across your LNG operation. This is an industry with a large and diverse set of operational data, production data, meta data and financial data. In a digital transformation, all this data must be brought together and made accessible from a centralized place. This could be a data platform or a digital twin, but, most importantly, this transformation is about combining the data from multiple sources so it is made meaningful and can be accessed by anyone from across the operation or even the entire value chain.

For example, monoethylene glycol (MEG) is injected into pipelines for thermodynamic hydrate prevention. Without knowing the minimum concentration for the current production rate, MEG is often either underdosed or overdosed, introducing risk of hydrate formation. The information needed to predict hydrate formation and to estimate the required MEG concentration, given operational conditions, is spread across production, sensors, piping and instrumentation diagrams and well data sources, as well as in pipeline layouts, height profiles and laboratory data. It is not until this data is consolidated and made available for easy use that it can be leveraged to estimate the current MEG concentration and to compute a recommended maximum pipeline flowrate.

Put the data to work to gain real-time situational awareness. According to a McKinsey & Company industry report on the digital era of the autonomous plant,[1] a carefully determined combination of conventional technologies, artificial intelligence (AI), ubiquitous data, connectivity and collaboration can work in concert to consider the future state of refineries or petrochemical plants. While data is at the core of the digital plant, it must be part of a bigger strategy of digital solutions, working in tandem, to extract its full potential. Data has no real value until it is put in context, which requires layers of analytics to give it meaning.

Success will depend on fast and accurate information, in context, from across the LNG value chain. For example, sensor data—when contextualized—can help forecast potential incidents before they happen, enabling the operators to take decisive action before an incident occurs. Connecting data provides a gateway to the world of predictive maintenance, optimized uptime, reduced downtime, and a significant reduction in safety and environmental risk. In an environment with increasing regulations and greater transparency requirements, this window into the live operation can reveal where there is excessive waste, where efficiencies can be gained and what steps can be taken to optimize production even further.

The author's company has had conversations with Lundin Energy about what digitalization has done for its gas business. The following is how Lundin is working with the author's company to reduce its carbon emissions: "Trouble in the gas chain means you may have to burn the gas, which is not good for the environment," said Stig Pettersen, Principal Engineer Automation, Lundin Energy. "But we are looking into the data, using the dashboard for energy losses and carbon dioxide (CO_2) releases. Then, we can follow up, using key performance indicators. Now, there is even competition between the different shifts to release as little CO_2 as possible!"

Make smarter decisions that help you get closer to fully optimized production. There is no doubt that LNG companies want to lower their costs and operate more efficiently and sustainably. They also want to have the competence and capacity to invest in new technologies, and to ensure that those technologies are not wasted in cases of one-off use.

McKinsey & Company refers to digitally transformed refineries as "more profitable, safer, more reliable, more energy efficient, a more attractive workplace, able to leverage AI-enabled solutions and more sustainable." Automation is the ultimate target on a digital roadmap, which is when multiple digital solutions are deployed and connected across the operation, enabling asset-wide digital twins and optimizations across units.

For example, Wintershall Dea wanted to create a holistic overview of maintenance work to better analyze larger trends, such as the frequency of issues like corrosion, how often a particular component breaks down and how much the company is spending on corrective vs. preventive maintenance. By consolidating all its maintenance management data in the author's company's proprietary DataOps platform[a], Wintershall Dea was able to aggregate factors that cause equipment failure with reliability metrics and detailed cost breakdowns. The result is that the company can more easily draw conclusions about the reliability of its assets, improving its maintenance routines and optimizing production, thus saving Wintershall Dea's experts an estimated 10 hr/wk. While this example is more specific to natural gas and oil production, the same concept of predictive maintenance can easily be applied to LNG facilities.

A promising forecast for the LNG industry. It is expected that LNG will continue to grow in demand as clean energy sources become increasingly dominant. In anticipation of future LNG demand, more plants are being built and more investment is being made.

It is a challenging time to be an LNG operator. There is no shortage of new technologies and new tools to enable smarter and faster processes, but the real value is when you bring the software, devices and data together. Imagine an LNG environment in which downtime is nearly nonexistent, in which human error is nearly eliminated, in which safety routines and measures are more accurate and effective, and where operators have all the information they need to make better business decisions.

LNG players who think about digitalization in the long term and across the spectrum of assets and operations will come out the winners. Fully liberated and contextualized data is vital, and those who use it to their advantage will be well-positioned when the demand strikes. **GP**

NOTE

[a] Cognite's Data Fusion™ platform

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Complete literature cited available online at www.GasprocessingNews.com.

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Redundancy via KVM technology keeps critical systems accessible

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The proliferation of computers and IT-based systems in industrial process automation has created a need for advanced and flexible system access to these computers. This digitalization trend creates a significant demand for more data to be managed, monitored, secured and evaluated.

In turn, organizations are implementing redundancy approaches through keyboard-video-mouse (KVM) technology to ensure critical systems are available and instantly accessible to any authorized user.

KVM refers to the interfaces of a computer. KVM devices help separate computers and their users. Operators instead access, extend, switch or distribute computer signals using dedicated CAT cables, optical fibers or standard IP-based network infrastructures and provide them again at the remote workplace in high resolution and with imperceptible latency. That allows for the implementation of comprehensive redundancy concepts for security-relevant and mission-critical applications.

KVM components explained. Fundamental KVM equipment includes extenders, switches and matrix systems. KVM extenders expand computer signals 1:1. KVM switches enable a 1:n connection (i.e., several computers can be operated using fewer peripherals from one console). If several workplaces access several computers simultaneously as an n:m connection, the installation becomes even more flexible. KVM matrix systems, which can flexibly map even the largest IT installations, offer this possibility.

Matrix systems consist of three components:

1. Computer modules (CPUs), which forward signals from computers to a matrix
2. A central module, which connects user consoles and computers
3. Console modules (CONs) to connect the consoles on which users work.

KVM systems enable the operation of multiple computers remotely in real time, without software installation, and independent of the operating system, thus saving peripherals. One of the main advantages of using KVM equipment is the simple implementation of security concepts. The computers are in a central, air-conditioned server room, protecting them from unauthorized access. KVM systems can be used to implement a variety of redundancy concepts to increase cybersecurity significantly. Redundancies also enable operators to switch to a redundant system even if a line or system component fails. Thus, they can continue their work immediately, securely, intuitively and in a familiar environment.

Ensuring security through redundancies. KVM systems offer numerous options for creating redundancies for mission-critical applications. Depending on the complexity and requirements of individual applications, the respective redundancy concept can be either relatively simple or complex. Redundancies back up either only the KVM system (**FIG. 1**), the computer side (**FIG. 2**), the console side or the entire application. Redundancy can be previously ensured by using a local switch for smaller applications.

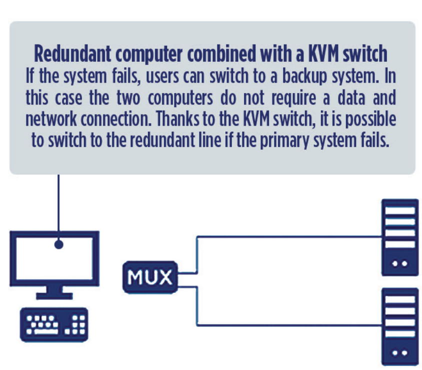

FIG. 1. Redundant computer combined with a KVM switch.

Complex application redundancy. Sensitive security-critical areas and control rooms go one step further and require a completely redundant technical

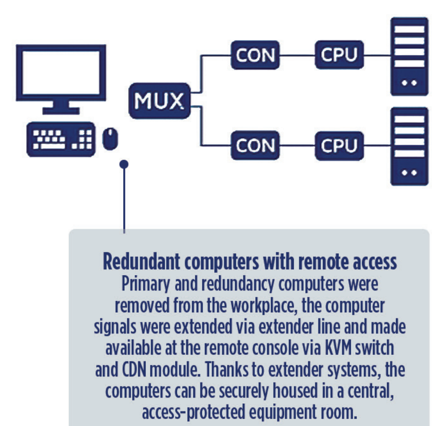

FIG. 2. Redundant computers with remote access.

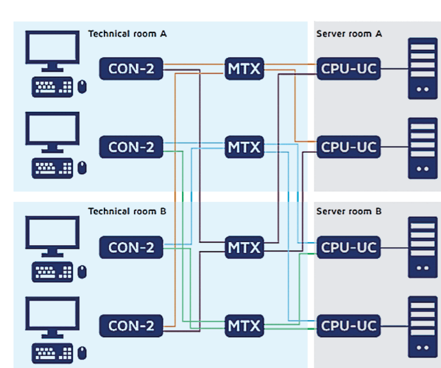

FIG. 3. Technical server room.

Keyboard-video-mouse (KVM) systems help separate computers and their users. They enable the operation of multiple computers remotely in real time, without software installation, and independent of the operating system, thus saving peripherals.

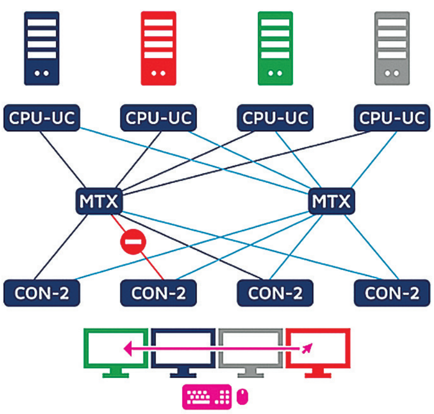

FIG. 4. Multi-monitor console with four monitors.

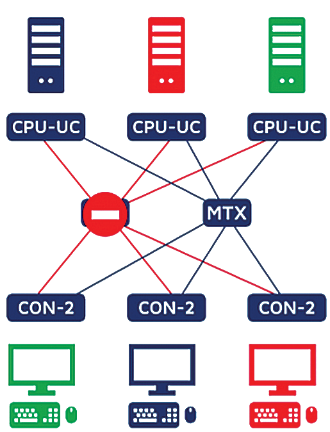

FIG. 5. MTX 1 connects Consoles 1, 2 and 3 to the blue, green and red computers.

area and control room. KVM can provide an ideal solution for these requirements, as well.

What if Technical room A fails due to a fire in the example application (**FIG. 3**), and in Server room B, a KVM matrix and a server fail simultaneously (e.g., due to a software bug)? In the worst case, one of the two control rooms fails, while one of the consoles fails in Control room A.

With a complex full redundancy of all KVM components, systems and premises, employees could still complete their work undisturbed—even in the case of such an extreme scenario.

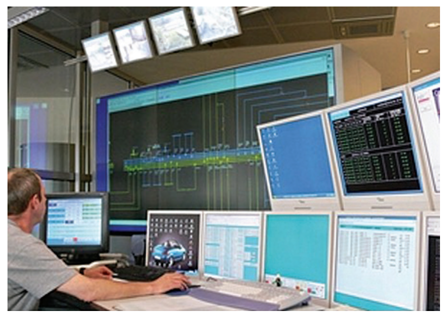

FIG. 6. Technical room.

FIG. 7. High-voltage control center.

Operating several computers on multi-screen consoles. **FIG. 4** shows a multi-monitor console with four monitors, each switched to a different computer thanks to the implemented cross-display switching function. This function switches keyboard and mouse signals, whereas the video signal remains permanently connected to the corresponding computer.

Operators can work on multiple computers to monitor numerous processes simultaneously. For example, if one of the CON-2 connections is interrupted, the respective CON-2 module automatically switches to the redundant matrix. Typically, all other CON-2 modules would remain on the primary matrix, which would result in an inconsistent console in which cross-display switching would no longer work.

Thanks to a "sync workplaces" function implemented in the matrix, the failed CON module automatically switches to the redundant matrix within milliseconds and takes all other CONs along. For this purpose, the admin sets up a script in advance using the configuration panel of the matrix systems, enabling the matrices' switching equality. Therefore, all CON modules are changed to the redundant matrix, and cross-display switching still works properly. This results in consistent switching of the CON modules.

Switching equality of matrices. Two crucial advantages of redundantly designed matrix installations are the automatic switching to the redundant KVM matrix if the primary matrix fails and the automatic switching equality between the primary and redundant matrix.

In **FIG. 5,** MTX 1 connects Consoles 1, 2 and 3 to the blue, red and green computers. If the power supply to the primary matrix fails, CONs and CPUs switch automatically to MTX 2. Due to the instinctive switching states of both matrices, users can continue their work immediately. This is ensured by a script stored and set up in advance in the configuration panel of the matrix systems, which lets users switch the matrices simultaneously.

Case study: KVM in Wiener Netze, a leading power producer maximizes availability and reliability. Major energy suppliers provide millions of people with electricity, gas and heat every day. The flipped switches must work uncompromisingly and error-free. In addition to ensuring the voltage level and load distribution, the control center employees are responsible for using and monitoring the equipment.

Complex control centers and data management systems require large computer landscapes and a wide variety of peripheral hardware. Such was the case with Wiener Netze GmbH, which provides the basic electricity, natural gas and district heating supply for Vienna, Austria, parts of Lower Austria and Burgenland. With around 2,500 employees, Wiener Netze creates, maintains and monitors the infrastructure and distributes electricity, gas, district heating and telecommunications where they are needed.

With the help of a KVM matrix switch, it is possible to decouple the complex computer technology from the workstations and outsource it to a specially equipped technical room (**FIG. 6**). The distance to the remote computers is bridged by corresponding computer and workstation modules, which correspond to the central matrix via CAT or fiber op-

tic cables. These allow access to computer technology in the background as if the operators were sitting directly onsite.

Control room clusters on the smart campus form the security area of Wiener Netze and must remain accessible. Therefore, the highest availability and security are essential for this project. For this reason, all infrastructures in the control rooms are entirely redundant, monitored and controlled with the aid of modern technology.

All computers of the control rooms were moved to a technical room and connected to KVM matrix switches. KVM peripheral modules extend and make computer signals available at the control rooms' workstations, each equipped with six screens. In medium-voltage control rooms, each console is provided with 10 monitors.

The high-voltage control center (**FIG. 7**) is the largest in the control room cluster. Upon entering, a display wall equipped with 6-m × 4-m Barco LED cubes immediately catches one's eye. Located directly behind it is one of the technical rooms, where several 19-in. server racks are equipped with state-of-the-art equipment so that the staff in the control room can carry out their tasks smoothly and continuously.

All control room workstations are structured similarly, making it easy for employees to change between them quickly. This way, they can still perform their usual tasks despite working on another desk.

This solution's key advantage is that all computer sources are connected to a matrix switch, extending the signals back to the consoles. This lets employees access the required computers from any controller position.

In the central server room, a total of 40, 19-in. racks were equipped and installed, leading to immense computing power. This is where the two fully mirrored and redundant KVM matrix switches are located.

All computer sources can be switched to all workstations thanks to KVM matrices. Predefined user rights make it possible to determine which users can access which computers.

Redundancy done right. Redundantly designed IT infrastructures using KVM systems provide numerous advantages. Reliable and always available devices, including redundancies, make a KVM installation a safe investment with advancement opportunities in the future. From simple setups with extender lines to complex concepts for fully redundant infrastructures with automatic switching to backup systems or redundant control rooms, the possibilities for designing redundant structures with KVM systems and thus increasing application security are endless. **GP**

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Case study: Sour condensate NGL export pumps seal failure

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In a facility, a frequent seal failure occurred on two sour condensate natural gas liquids (NGL) export pumps. After dismantling and inspecting one of the seals, it was determined that the seal had high contamination on the inner and the outer seals in addition to high-temperature failure for the outer seal elastomer (dry running seal, mating ring O-ring).

The pump owner reported frequent seal failures and requested pump specialists to oversee a comprehensive investigation. A site visit was conducted by the pump specialists to gain a better understanding of the pump and seal systems.

Additionally, previous seal failure reports were reviewed covering the period from 2014–2017. This case was considered to be an exceedingly high seal failure rate, with a mean time between failures (MTBF) of ~7 mos, considering that only one of the two pumps is typically in operation. This is much lower than the seal design life of 36 mos.

Unit A non-drive end (NDE) seal leak incident investigation. As per the provided data, the Unit A NDE seal failed after less than 1 mos of operation while the pump was not running and resulted in leakage to the atmosphere, triggering the lower explosive limit (LEL) alarm in the plant. The pump was shutdown 7 hr before the alarm. FIG. 1 shows the pump discharge pressure and the seal leakage detection from the time of the pump shutdown to the time where the alarm was triggered.

FIG. 2 shows the pressure trend for the drive end (DE) and the NDE seal leakage detection pressure for the complete 23-d duration of the seal operation.

The inspection of the seal at a local facility showed the following:

- High contamination on inner and outer seals (FIG. 3)
- Contamination material was partially metallic (i.e., attracted to magnets)
- Inner seal dynamic O-ring had a significant amount of contaminated materials stuck to it
- Outer seal mating ring O-ring was hardened and cut due to high temperature
- Inner and outer seal faces were showing heavy wear marks.

Seal failure analysis. Based on the collected data, the most logical scenarios for the failure of the Unit A NDE mechanical seal are listed here:

1. The assessment of the pump's 23 d of operation shown in FIG. 2 shows that the NDE seal leakage detection pressure maintained an approximate average of 20 psig, which exceeds the alarm limit set at 10 psig. This could be caused by one or a combination of the below:
   a. A stuck check valve as per American Petroleum Institute (API) Plan 76. This is highly probable as it might create back pressure in the cavity between the two seals.
   b. A passing API Plan 76 drain valve or a passing mechanical seal drain valve. This might result in flow entering the seal cavity.
   c. A passing pump drain valve or passing API Plan 23 drain valve. This is also possible and might result in pressurizing the seal cavity if one of its drain valves is passing.
2. The high seal cavity pressure had a significant effect on the outer seal. This pressure, as well as the high contamination in the process liquid, are believed

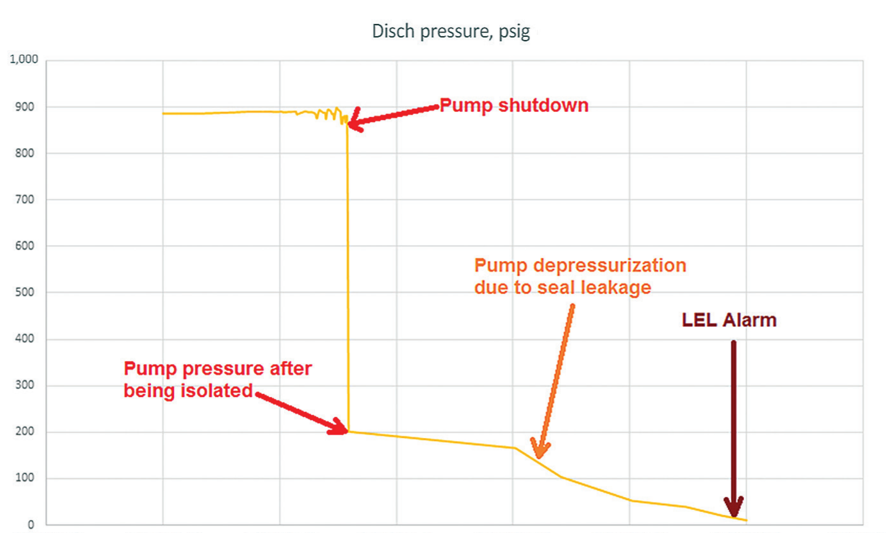

FIG. 1. Pump depressurization due to seal leakage.

to have caused the high outer seal temperature, which hardened and broke the outer seal, mating ring O-ring shown in **FIG. 3.** This resulted in the failure of the outer seal, which is supported by the reduction in the NDE seal cavity pressure from 25 psig to 2 psig (**FIG. 2**).

3. During the operation of Unit A, the pump casing was at a suction pressure of ~200 psig. However, the pressure measurements show that the pump pressure dropped from 200 psig to 5 psig during the 8 hr after the pump shutdown, as shown in **FIG. 1.** This is believed to be caused by a failure of the NDE inner seal due to hang-up, seal faces wear and/or the presence of dirt between the two seal faces.

Sour condensate NGL export pumps frequent seal failures. A design assessment was completed for the pump system from the suction column to the pump discharge and for the seal auxiliary system to identify any potential design concerns. In addition, the PI process data were analyzed to determine the pump operating conditions. The main points that may have caused the low reliability of the seal are listed here:

1. The pump suction line has a permanent strainer with a maximum allowable differential pressure of 0.5 psi. The piping and instrumentation diagram (P&ID) shows that the available net positive suction head available (NPSHA) and the net positive suction head required (NPSHR) are close; therefore, the use of suction strainer is not recommended.
2. The pump process data showed that the pumps were operating at a higher differential pressure than the design, as shown in **FIG. 4.** This was believed to be caused by a higher liquid specific gravity.
3. The pumps were consistently operated between 450 gal/min and 900 gal/min (**FIG. 4**). As the pumps have a best efficiency point (BEP) of ~1,080 gal/min, the pumps were operated for a long time outside the preferred operating region, which ranges from 750 gal/min–1,300 gal/min. This resulted in high flow

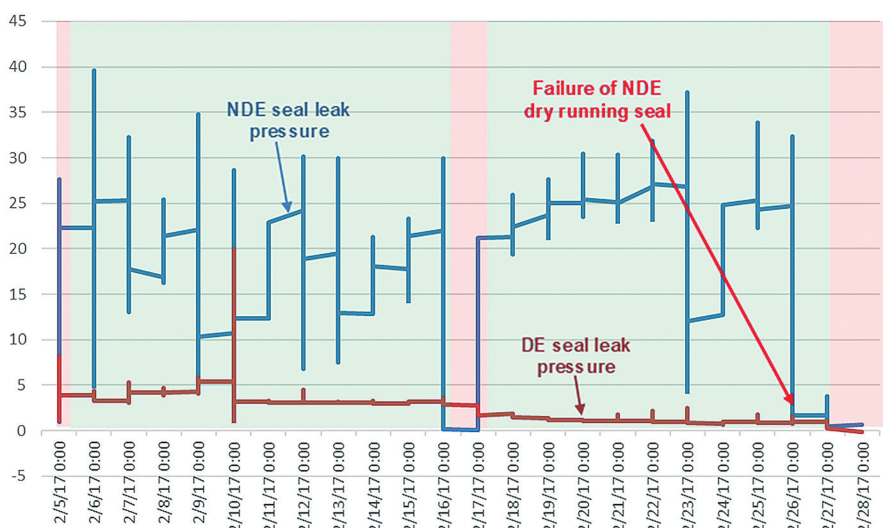

FIG. 2. DE and NDE seal leak pressure measurements.

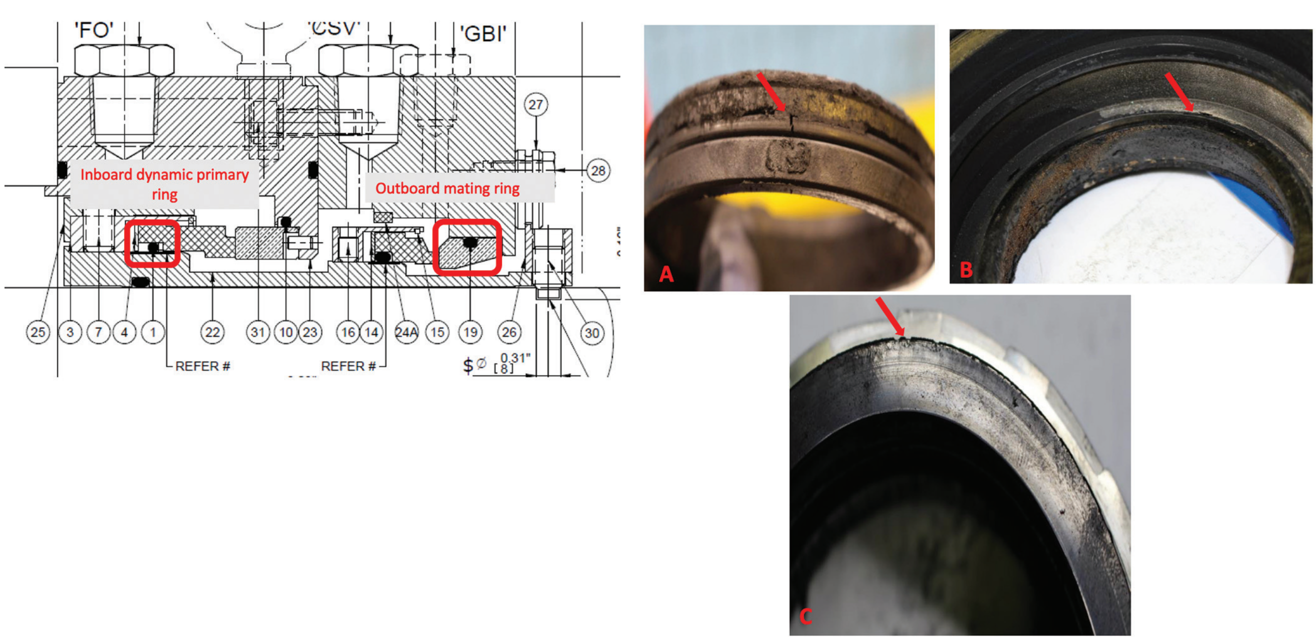

FIG. 3. The outboard mating ring showed heavy contamination and the O-ring was hardened and broken (A and B); the inboard primary dynamic ring showed excessive wear and OD chipping and contamination (C).

turbulence and pump vibration, significantly affecting seal life. If an increase in the current process flowrate is not expected, consideration should be given to re-rate the pumps for the actual operating condition. This will help improve pump and seal performance, and reduce pump power consumption.

4. The process operating temperature ranges from 260°F–270°F (127°C–132°C), which is higher than the normal operating temperature of 246°F (119°C) specified in the pump datasheet.
5. The failure analysis of the final failed seal showed pitting corrosion in critical locations, including O-ring surfaces. A sample of the condensate liquid between the main and backup seals was sent for analysis to identify the cause of pitting. The analysis showed no indication of any major corrosive agents. Pitting may be caused by an isolated incident due to a process upset. If future data shows pitting, material upgrade to duplex or super duplex should be considered.

Seal system design analysis. A design assessment was conducted for the seal design parameters and the seal auxiliary system to identify any potential design concerns. The main points that may have contributed to the low reliability of the seal include:

1. The datasheet shows that the liquid specific gravity is < 0.5 with an operating temperature of 246°F (119°C). The pump specialists experienced low seal reliability for many pumps in such applications supplied with vendor seals. Low specific gravity liquids are considered to be difficult to seal. For this reason, API 682 recommends Arrangement 3 seals for liquids with < 0.5 specific gravity, such as this pump with a specific gravity of 0.497.
2. The site temperature measurement for seal API Plan 21 flushing liquid during the site visit showed that the inlet and outlet temperatures for the cooler were 176°F (80°C) and 140°F (60°C), respectively. Although this is not in line with the typical process temperature, it shows that sufficient cooling is happening at the cooler. For proper seal performance, pump standards mandate that the stuffing box pressure exceed the vapor pressure by at least 50 psi. This can be accomplished by increasing the stuffing box pressure or decreasing the liquid vapor pressure via cooling methods. In this pump case, the process data indicated that sufficient cooling was provided.
3. The seal drawing shows that two 0.125-in. orifices designed to achieve a seal flush flowrate of 3 gal/min were used for API Plan 21. Calculations showed that flowrate will be less than 3 gal/min since the takeoff for API Plan 21 was from the discharge of the first stage. For that reason, the seal vendor was contacted to verify orifices requirements. Based on the vendor response, it was recommended to leave one of the restrictive orifices as it was and to open the other to full bore, as shown in **FIG. 5.**
4. The current seal follows API Plan 76 while company standards mandate API Plan 75. **FIG. 6** shows the difference between these two API 682 seal plans. Plan 75 should be used whenever the liquid has heavy ends to prevent the liquid accumulation between the two seals. When Plan 76 is used, the liquid will accumulate between the two seals; this can cause a failure of the dry running backup seal, as it is designed for a gas phase in normal operation. For that reason, it is recommended to change the seal plan from Plan 76 to Plan

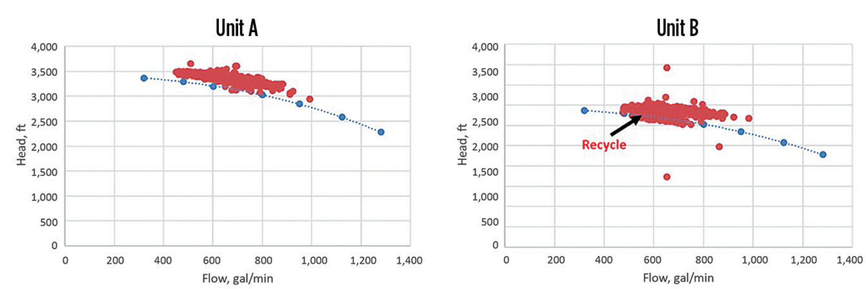

FIG. 4. Unit A and B operating flow and head.

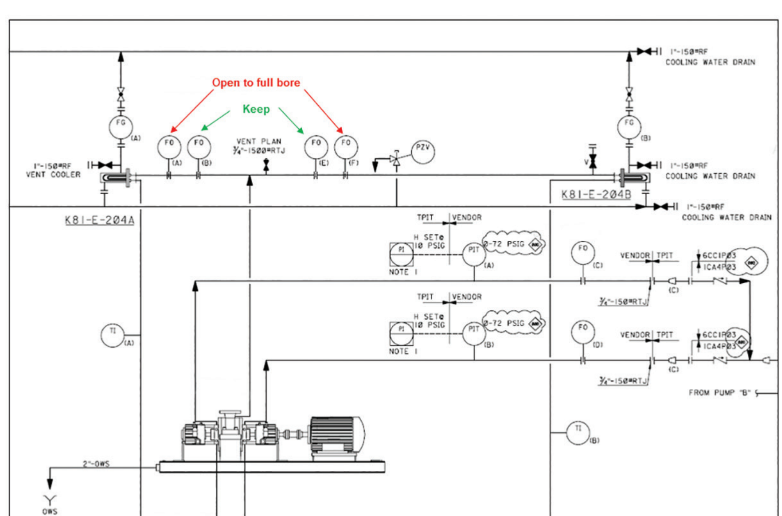

FIG. 5. Location of orifices.

Pumping light hydrocarbons such as NGL is challenging. Repetitive mechanical seals failures can occur due to the very low relative density (specific gravity) of such fluids. Arrangement 3 of API Plan 53B is designed with a seal barrier liquid different than the pumping fluid.

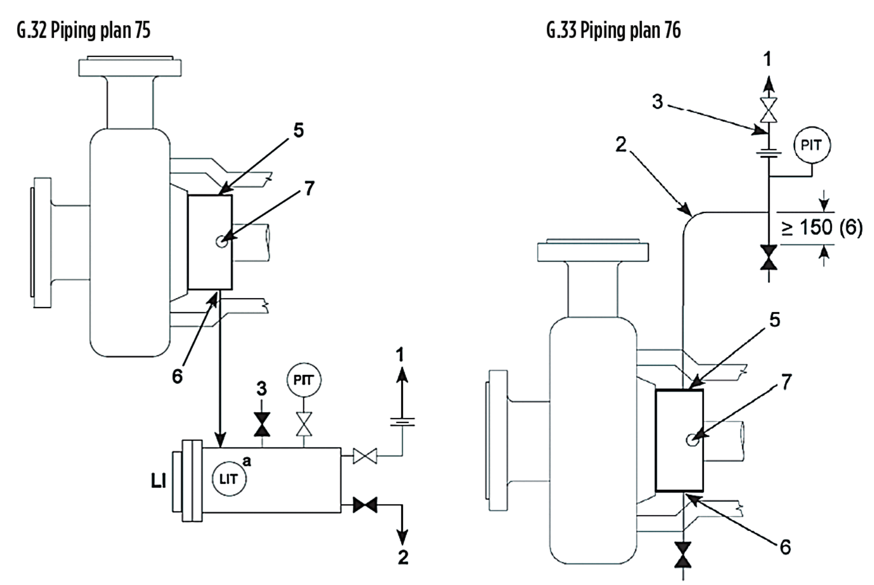

FIG. 6. API 682 seal Plan 75 and 76 configurations. Source: API.

75. This can have considerable cost impact. A simplified Plan 75 may be considered based on a level indicator rather than a level transmitter required by company standards. In such a case, the operating procedure should ensure daily level checks by the plant operator.

5. The visual inspection of the seal auxiliary system at the plant showed that the seal chamber vent line was blinded. This means that the seal will not be properly vented, which can cause seal failures especially after pump priming. Therefore, the inboard and outboard seal vent lines must be connected to the closed drain system or the flare header to ensure venting of the stuffing box when needed. Further enhancement may be achieved if pressure indicators can be added at these two vent lines to show the stuffing box pressure. This will aid in troubleshooting future mechanical seal failures.

RECOMMENDATIONS AND ACTION PLAN

The required actions to resolve the fundamental pump and seal system design deficiencies include:

- Remove the pump suction strainers. If a large foreign object or high quantity of sludge is expected, the plant may keep a large-opening strainer (> 0.25 in.) to ensure the strainer will be cleaned when the differential pressure reaches 0.5 psi.
- If an increase in the current process flowrate is not expected, consideration should be given to re-rate the current pump for the actual operating conditions.
- Connect the inboard and outboard seal vent lines to the closed drain system or the flare header to ensure venting of the stuffing box when needed. A further enhancement may be achieved if pressure indicators can be added at the vent lines to show the stuffing box pressure.

Specific seal design recommendations. Recommended solutions for the seal design can be divided into two main options:

- **Option 1:** Keep the existing Arrangement 2 seal (dual-unpressurized seal) and attempt to resolve any deficiencies in it.
- **Option 2:** Use an Arrangement 3 seal (dual-pressurized seal) rather than the current Arrangement 2 seal, as recommended by API 682 for applications with a specific gravity < 0.5.

Option 1: Dual-unpressurized seal (Arrangement 2). To enhance the seal performance, remove the restriction caused by one of the two seal API Plan 21 orifices. This can be done by opening one orifice to full bore size (i.e., no flow restriction)—as indicated in FIG. 5—to avoid piping modifications that may be needed if the orifices were removed completely.

If significant contamination is observed or expected, consider adding a filter to API Plan 21. Re-install the flush line temperature measurement downstream of the API Plan 21 cooler. If corrosion pitting is still observed for future seals, verify the cause of the pitting and upgrade the seal material, as needed. Consider changing seal manufacturers to other seal vendors if issues are not fully resolved. In such cases, ensure the new seal is selected based on actual site operating conditions and request that the seal vendor provide its experience list for seals in similar operating conditions with satisfactory performance (i.e., at least 3 yr of MTBF).

Option 2: Dual-pressurized seal (Arrangement 3). As stated previously, low specific gravity liquids are difficult to seal. Therefore, API 682 recommends arrangement 3 seals for liquids < 0.5 specific gravity. This can be a very viable option, particularly if the seal material is upgraded from 316SS to duplex or super duplex.

The recommended seal plan for such a case will be API Plan 53B. The main benefit for an Arrangement 3 seal is that it relies on the barrier liquid to lubricate the seal faces. In such a case, a high-quality barrier liquid can be used to ensure high seal reliability. **GP**

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Fincantieri begins construction on largest U.S. LNG barge

Fincantieri Bay Shipbuilding has begun construction on the largest LNG bunkering barge ever built in the U.S.

Bay Shipbuilding is expected to complete construction on the barge in late 2023 under contract with Crowley, the largest independent operator of tank vessels in the U.S. Crowley will operate the vessel under a long-term charter with Shell.

The 416-ft vessel, which will have the capacity for 12,000 m^3 (3.17 MMg) of LNG, will be the largest Jones Act-compliant vessel of its kind, and the second Jones Act-compliant bunker barge Shell has under a time charter in the U.S.

Serving the U.S. East Coast, the vessel will be used to help expand current LNG network capacity and meet demands for cleaner energy sources for ships.

NEC, University of S. Alabama ink agreements on CO_2 capture technology

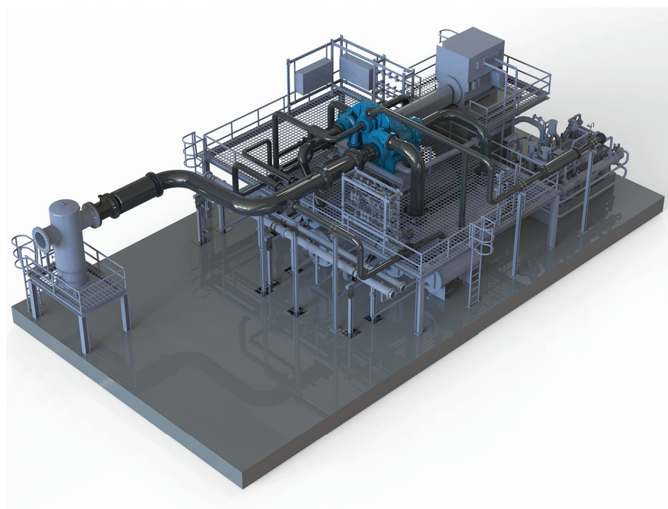
Norton Engineering Consultants Inc. (NEC) has entered license agreements with the University of South Alabama (USA) to exclusively produce and supply non-volatile aqueous ionic amines (AIMs) for general use and to incorporate AIMs into processes for CO_2 capture from combustion sources, including NEC's proprietary flue gas scrubbing technology.

NEC and USA intend to introduce this technology to industrial clients in the oil refining, petrochemical, manufacturing and power industries to reduce emissions of CO_2 and possibly other greenhouse gases (GHGs).

Linde Engineering begins plant for extracting H_2 from natural gas pipelines

Linde Engineering has started the world's first full-scale pilot plant in Dormagen, Germany, to showcase how hydrogen (H_2) can be separated from natural gas streams using Linde's HISELECT powered by Evonik membrane technology.

The process is a key enabler for scenarios in which H_2 is blended with natural gas and transported via natural gas pipelines. The blended gas can consist of between 5% and 60% H_2. Membranes are then used to extract H_2 from these natural gas streams at the point of consumption. The resulting H_2 has a concentration level of up to 90%. When further processed with Linde Engineering's pressure swing adsorption technology, a purity of up to 99.9999% can be achieved.



Atlas Copco to supply CO_2 compressor to biofuels plant project in Europe

Atlas Copco Gas and Process will be supplying CO_2 compression equipment to a renewable biofuels plant project in Europe. The equipment will be used in an 820,000-tpy biofuels facility, located at the Shell Energy and Chemicals Park Rotterdam, the Netherlands.

The facility will be among Europe's largest plants to produce sustainable aviation fuel (SAF), renewable diesel and renewable naptha made from biowaste. A facility of this size can produce enough renewable diesel to avoid 2.8 MMtpy of CO_2 emissions, or the equivalent of taking more than 1 MM European cars off the roads.

In addition to the fuel production, an essential building block of Shell's endeavor is the carbon capture and pipeline transport of CO_2. A byproduct from different plant processes, including blue H_2, the CO_2 will be compressed to a pressure of 42.5 bar by the Atlas Copco Gas and Process' five-stage turbocompressor. The machine is designed to compress 43.5 tph.

Expected to start production in 2024, the new facility will help both the Netherlands and the rest of Europe in meeting internationally binding emissions reduction targets. It will produce low-carbon fuels such as renewable diesel from waste in the form of used cooking oil, waste animal fat and other industrial and agricultural residual products, using technology developed by Shell.

Baker Hughes, EGPC to collaborate on flare recovery initiative

Baker Hughes has signed an MoU with the Egyptian General Petroleum Corp. (EGPC) that aims to establish and drive a flare recovery initiative to support emissions recovery and reduction across Egypt's upstream and downstream oil and gas operations.

To enable flare recovery from oil and gas sites across Egypt, Baker Hughes will leverage its portfolio of emissions management solutions, including flare management technology, compression, gas turbines and integrated processing systems that can help in the measurement, management, recovery and utilization of flare gas.

In addition, Baker Hughes solutions—including flare.IQ—will contribute to digitalizing emissions management infrastructure by enabling EGPC to pull information about its flare systems to calculate optimum levels of flare efficiency and help reduce methane emissions.

NOVATEK, ENN ink sales and purchase agreement on long-term LNG supply

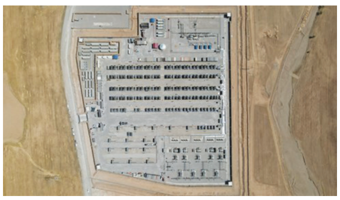
PAO NOVATEK's wholly owned subsidiary, NOVATEK Gas & Power, and ENN LNG have signed a long-term LNG sale and purchase agreement (SPA) for the LNG produced from the Arctic LNG 2 project.

The SPA stipulates the supply of approximately 600,000 tpy of LNG from the Arctic LNG 2 project for a term of 11 yr. The LNG will be delivered on a delivered ex ship (DES) basis to ENN's Zhoushan LNG Receiving Terminal in China.

Gazprom completes feasibility study for Soyuz Vostok gas pipeline project

Gazprom has signed a statement on the results of the consideration of the feasibility study for the Soyuz Vostok gas trunkline construction project. As per the feasibility study, the pipeline will stretch for 962.9 km in Mongolian territory, the pipes will be 1,400 mm in diameter, and five compressor stations will be installed. The scope of works performed as part of the feasibility study, which includes the calculation of investment and operating costs, is extensive enough for the study to serve as front-end engineering and design (FEED) documents. Mongolian companies performed the required onsite surveys, engineering and environmental mapping and route analysis for the Soyuz Vostok project. The data obtained were used in the development of the gas pipeline route.

Aggreko completes the Middle East's largest flare gas-to-power project to date



Aggreko has completed commissioning of the largest flare gas-to-power project in the Middle East to date. The plant is situated nearby the Saqala Field, Garmain block, Southeast Kurdistan.

The 165-MW modular power plant has run at full capacity for 72 hr in the project's final site acceptance test, marking successful on-time, on-budget delivery. The plant is run on approximately 40 MMft³d of associated petroleum gas from the Saqala Field, saving 840 tpd of CO_2 and cutting flaring by a third.

Enbridge Gas' Canadian H_2-blending project is fully operational

Enbridge Gas, in partnership with Cummins Inc. and with support from Sustainable Development Technology Canada, the Canadian Gas Association and NGIF Capital Corp., has announced that its hydrogen (H_2)-blending project is now fully operational and successfully serving the Markham, Ontario, community.

The $5.2-MM pilot-blending project involves enhancements to the existing Markham power-to-gas facility, which was built through a JV between Enbridge and Cummins in 2018 to help balance Ontario's electricity supply and demand by storing the province's surplus electricity as pure H_2 until it is needed.

Through this project, clean H_2 from the facility is now also being injected into a portion of Enbridge Gas' existing natural gas system serving about 3,600 end users in Markham, Ontario. Blending H_2 with traditional natural gas reduces GHG emissions, enabling lower carbon natural gas service delivery without impacting energy costs, reliability or safety.

This project will eliminate up to 117 tpy of CO_2 emissions, moving the City of Markham further toward its objective of net-zero emissions by 2050.

Evonik has delivered SEPURAN membranes to more than 1,000 reference plants

Since the product launch in 2011, Evonik has delivered gas separation membranes to more than 1,000 reference plants worldwide as of the end of 2021. The company is experiencing continued demand in biogas, nitrogen (N_2), hydrogen (H_2) and natural gas applications. The expansion of existing production capacities at the Austrian site in Schörfling am Attersee is progressing.

At the heart of Evonik's SEPURAN membrane technology are polymer-based, hollow-fiber membranes made of the high-performance polymer polyimide developed in-house. SEPURAN membranes make it possible to separate gases such as methane (CH_4), N_2 or H_2 from gas mixtures. SEPURAN N_2 membranes for efficient N_2 generation are used, for example, to inert aircraft tanks. SEPURAN Noble membranes extract H_2 transported through natural gas pipelines selectively from the CH_4/H_2 gas mixture at the delivery points. SEPURAN NG membranes enable efficient natural gas processing from gas sources with high CO_2 concentration.

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